(Revised 3-31-05)

CA-IR-251

Ref: HECO-1310 (HEI Billings).

The referenced workpaper support was provided in a "Word" document file. Please provide the following:

a. Please provide HECO-1310 in an Excel spreadsheet file format with intact formulae, cell references and file links.

b. Please provide actual 2004 HEI charges to HECO, showing direct and allocated charges in a format comparable to the 2003 data set forth on HECO-1310.

c. Referring to item (a) above, please provide additional HEI workpapers supporting the conversion of 2003 direct labor hours and shared labor hours into their respective labor dollars.

d. Referring to items (a) and (c) above, please provide a copy of the underlying workpapers and calculations supporting the derivation of any standard hourly labor rates used therein.

HECO Response:

a. The electronic file with the requested information will be provided under separate transmittal.

b. The actual 2004 HEI charges to HECO, showing direct and allocated charges in a format comparable to the 2003 data set forth on HECO-1310, is provided on pages 163 through 167 of this response.

c. A proforma bill is available for the period 1/1/03 to 12/31/03 which was run specifically for rate case purposes and excludes any incentive compensation from the employee labor rates. The proforma bill was run using actual 2003 direct labor hours and shared labor hours along with 2003 actual nonlabor dollars. The amounts reflected on the proforma bill agree to the 2003 amounts reflected on HECO-1310 pages 1 through 3. This proforma bill is voluminous and contains confidential employee labor rates (which include actual salary,

CA-IR-251

Ref: HECO-1310 (HEI Billings).

The referenced workpaper support was provided in a "Word" document file. Please provide the following:

a. Please provide HECO-1310 in an Excel spreadsheet file format with intact formulae, cell references and file links.

b. Please provide actual 2004 HEI charges to HECO, showing direct and allocated charges in a format comparable to the 2003 data set forth on HECO-1310.

c. Referring to item (a) above, please provide additional HEI workpapers supporting the conversion of 2003 direct labor hours and shared labor hours into their respective labor dollars.

d. Referring to items (a) and (c) above, please provide a copy of the underlying workpapers and calculations supporting the derivation of any standard hourly labor rates used therein.

HECO Response:

a. The electronic file with the requested information will be provided under separate transmittal.

b. The actual 2004 HEI charges to HECO, showing direct and allocated charges in a format comparable to the 2003 data set forth on HECO-1310, will not be available until the end of March 2005 since the annual true-up to reflect actual loading rates is currently being developed. However, the information will be provided as soon as it becomes available and will be made available no later than March 31, 2005.

c. A proforma bill is available for the period 1/1/03 to 12/31/03 which was run specifically for rate case purposes and excludes any incentive compensation from the employee labor rates. The proforma bill was run using actual 2003 direct labor hours and shared labor hours along with 2003 actual nonlabor dollars. The amounts reflected on the proforma bill agree

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benefits and payroll taxes and loadings). One copy each will be provided to the Consumer Advocate and the Commission under protective order.

In addition, the proforma bill was run using the 2004 allocation factors for all allocation factors except the common equity based allocation factors. The common equity based allocation factors are 2005 estimated allocation factors based upon the estimated 12/31/04 common equity of the companies. All allocation factors were applied to the 2003 shared charges because the 2004 shared charges were not available at the time the rate case estimate was being developed. See HECO's response to CA-IR-252 a. for the workpapers and supporting documents used in the development of each allocation factor.

d. Please see the attached workpapers on pages 160 through 162 of this response for a sample template used for calculating hourly labor rates for employees. Labor rates are based upon actual labor costs for salary, benefits and payroll taxes and loadings are added onto labor costs for normal departmental costs. These costs include those with respect to office supplies, dues and subscriptions, meeting and seminars, pension costs, computer costs

to the 2003 amounts reflected on HECO-1310 pages 1 through 3. This proforma bill is voluminous and contains confidential employee labor rates (which include actual salary, benefits and payroll taxes and loadings). One copy each will be provided to the Consumer Advocate and the Commission under protective order.

In addition, the proforma bill was run using the 2004 allocation factors for all allocation factors except the common equity based allocation factors. The common equity based allocation factors are 2005 estimated allocation factors based upon the estimated 12/31/04 common equity of the companies. All allocation factors were applied to the 2003 shared charges because the 2004 shared charges were not available at the time the rate case estimate was being developed. See HECO's response to CA-IR-252 a. for the workpapers and supporting documents used in the development of each allocation factor.

d. Please see the attached workpapers on pages 160 through 162 of this response for a sample template used for calculating hourly labor rates for employees. Labor rates are based upon actual labor costs for salary, benefits and payroll taxes and loadings are added onto labor costs for normal departmental costs. These costs include those with respect to office supplies, dues and subscriptions, meeting and seminars, pension costs, computer costs, utilities, etc. There is no profit or premium component to the labor rates.

Due to the confidential nature of employee salary and benefit information, the actual loaded labor rate calculations for HEI employees (pages 160-162) are only available for review at the HEI Controller's office. Please contact Irene Sekiya at (808) 543-4778 to arrange to review this information.

HEI Loaded Labor Rates
Department Name
January 1, 2003
Page 1 of 3

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		Salary, payroll taxes, and benefit costs NAME	2003 Department Name Costs	Legend	Source
DATA					
Salary current annual		0		YER	Salary A
Payroll Taxes					
FICA	Rate 6.20% on up to $87,000	0		AC	YER-P
	Rate 1.45%	0		AC	YER-P
FUTA	Rate 0.8% on up to $7,000	0		AC	YER-P
SUTA	Rate 0.41% on up to $30,200	0		AC	YER-P
TDI		0		NA	Salary C
Benefits - Annual costs for:					
Medical		0		YER-C	Benefits A
Dental		0		YER-C	Benefits A
Vision		0		YER-C	Benefits A
Group life Insurance		0		YER-C	Benefits A
Dependent life insurance		0		YER-C	Benefits A
AD&D		0		YER-C	Benefits A
FLEX Adjustment		0		YER-C	Benefits A
Long-term disability		0		YER-C	Benefits A
Qualified Pension/OPEB 22.254% of 1/1/02 salary		0		AC-A	Benefits B
Bonus		0		AC-C	Benefits C-1

2003 Available Hours		
Total compensated hours	0	0
Holidays	0	0
Vacation	0	0
2003 Available Hours	0	0

Legend

YER	Salary as of January 1, 2003
YER-C	Based on January 2003 annualized premiums/credits
YER-P	Based upon salary as of January 1, 2003, multiplied by the applicable tax rates.
AC	Actual cost as recorded in this department
AC-C	Actual cost but cost was recorded as corporate not departmental cost
AC-T	Actual cost as recorded by Treasurer
AC-I	Actual cost as recorded by VP Information Systems
AC-A	Actual cost as recorded by VP Admininstration (and VP Info Systems and Corporate RA as applicable)
AC-Z	Actual cost as recorded by the VP Administration & the Corporate Secretary
AC-P	Actual cost as recorded by the President & VP Administration (as applicable)
NA	Not Applicable

HEI Loaded Labor Rates

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HEI Loaded Labor Rates
Department Name
January 1, 2003
Page 2 of 3

2003
Department Name

RATES		Loaded Hourly Labor Rates NAME	Costs	Legend	Source
Salary		0.0000		YER	
FICA	Rate 6.20% on up to $87,000	0.0000		YER-P	
	Rate 1.45%	0.0000		YER-P	
FUTA	Rate 0.8% on up to $7,000	0.0000		YER-P	
SUTA	Rate 0.41% on up to $30,200	0.0000		YER-P	
TDI		0.0000		NA	
	Subtotal	0.0000			
Benefits					
Medical		0.0000		YER-C	Benefits A
Dental		0.0000		YER-C	Benefits A
Vision		0.0000		YER-C	Benefits A
Group life insurance		0.0000		YER-C	Benefits A
Dependent life insurance		0.0000		YER-C	Benefits A
AD&D		0.0000		YER-C	Benefits A
FLEX Adjustment		0.0000		YER-C	Benefits A
Long-term disability		0.0000		YER-C	Benefits A
Qualified Pension/OPEB		0.0000		AC-A	Benefits B
Executive incentive comp		0.0000		AC	
Bonus		0.0000		AC-C	Benefits C-1
Dividend Equivalent		0.0000		AC	
Other human resources costs		0.0000		AC-A	Benefits E
	Subtotal	0.0000			
oaded rate before departmental costs		0.0000			
Departmental Loadings					
HEI Loadings					
Office Supplies		0.0000		AC	
Computer software/supplies		0.0000		AC	
Subscriptions		0.0000		AC	
Books		0.0000		AC	
Membership fees / dues - other		0.0000		AC	
Telephone equipment		0.0000		AC	
Long Distance		0.0000		AC	
Copier		0.0000		AC-P	Copier A
Mailing Services		0.0000		AC-A	Mailing A
Rent buildings		0.0000		AC-A	Rent A-4
HEI corp info system expense		0.0000		AC-I	Info Sys A
Insurance - Directors & officers		0.0000		AC-Z	Insurance A
Insurance - GL, w/c, property, business tvl		0.0000		AC-Z	Insurance A
Depreciation-computer		0.0000		AC	
Depreciation-furniture & fixtures		0.0000		AC	
Depreciation - dept LH improve		0.0000		AC	
Depreciation - King Street		0.0000		AC-A	Depreciation A
Total HEI loadings		0.0000			
HECO loadings					
Rent-parking		0.0000		AC-A	Rent B
Total HECO loadings		0.0000			
Total loaded labor rate		0.0000			

HEI Loaded Labor Rates
Department Name
January 1, 2003
Page 2 of 3

		Loaded Hourly Labor Rates NAME	2003 Department Name Costs	Legend	Source
RATES					
Salary		0.0000		YER	
FICA	Rate 6.20% on up to $87,000	0.0000		YER-P	
	Rate 1.45%	0.0000		YER-P	
FUTA	Rate 0.8% on up to $7,000	0.0000		YER-P	
SUTA	Rate 0.41% on up to $30,200	0.0000		YER-P	
TDI		0.0000		NA	
	Subtotal	0.0000			
Benefits					
Medical		0.0000		YER-C	Benefits A
Dental		0.0000		YER-C	Benefits A
Vision		0.0000		YER-C	Benefits A
Group life insurance		0.0000		YER-C	Benefits A
Dependent life insurance		0.0000		YER-C	Benefits A
AD&D		0.0000		YER-C	Benefits A
FLEX Adjustment		0.0000		YER-C	Benefits A
Long-term disability		0.0000		YER-C	Benefits A
Qualified Pension/OPEB		0.0000		AC-A	Benefits B
Executive incentive comp		0.0000		AC	
Bonus		0.0000		AC-C	Benefits C-1
Dividend Equivalent		0.0000		AC	
Other human resources costs		0.0000		AC-A	Benefits E
	Subtotal	0.0000			
Loaded rate before departmental costs		0.0000			
Departmental Loadings					
HEI Loadings					
Office Supplies		0.0000		AC	
Computer software/supplies		0.0000		AC	
Subscriptions		0.0000		AC	
Books		0.0000		AC	
Membership fees / dues - other		0.0000		AC	
Telephone equipment		0.0000		AC	
Long Distance		0.0000		AC	
Copier		0.0000		AC-P	Copier A
Mailing Services		0.0000		AC-A	Mailing A
Rent buildings		0.0000		AC-A	Rent A-4

HEI Loaded Labor Rates
Department Name
January 1, 2003
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RATES	Loaded Hourly Labor Rates NAME	2003 Department Name Costs	Legend	Source
Other HECO Charges				
President's office	Unallocable or charge to the activity.		AC	
Other HEI Charges				
Computer supplies/other	Unallocable or charge to the activity.		AC	
Seminars - mainland	Unallocable or charge to the activity.		AC	
Seminars - air travel	Unallocable or charge to the activity.		AC	
Seminars - nonair	Unallocable or charge to the activity.		AC	
Seminars - hotels	Unallocable or charge to the activity.		AC	
Meals & entertainment	Unallocable or charge to the activity.		AC	
Local seminars	Designated as unallocable.		AC	
Seminars - misc	Designated as unallocable.		AC	
BOD expense	Unallocable or charge to the activity.		AC	
Stockholder expenses	Unallocable or charge to the activity.		AC	
Other A&G	Unallocable		AC	
Legal fees	Charge to the activity.		AC	
Insurance - Directors & Officers	Allocated to the individual		AC	See Insurance A
Medical benefits allocation	Included in benefits.		AC	
Dental benefits allocation	Included in benefits.		AC	
Vision benefits allocation	Included in benefits.		AC	
Group life allocation	Included in benefits.		AC	
Long-term disability allocation	Included in benefits.		AC	
Qualified benefit plan	Included in benefits.		AC	
Nonqualified directors plan	Unallocable		AC	
Flex credits	Included in benefits.		AC	
Other post retirement benefits	Included in benefits.		AC	
HR-administration	Included in benefits.		AC	
HR-benefits	Included in benefits.		AC	
Payroll taxes	N/A-payroll taxes on the current year salary is used		AC	
OTS exam	Designated as unallocable.		AC	
Rounding				
Total corporate secretary costs		0		
Total per general ledger				
Difference		0		

HEI Loaded Labor Rates
Department Name
January 1, 2003
Page 3 of 3

RATES	Loaded Hourly Labor Rates NAME	2003 Department Name Costs	Legend	Source
Other HECO Charges				
President's office	Unallocable or charge to the activity.		AC	
Other HEI Charges				
Computer supplies/other	Unallocable or charge to the activity.		AC	
Seminars - mainland	Unallocable or charge to the activity.		AC	
Seminars - air travel	Unallocable or charge to the activity.		AC	
Seminars - nonair	Unallocable or charge to the activity.		AC	

HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004 Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004 Shared Labor Hours	2004 Allocatio Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual
ACC	**Accounting**								
ACC 001	Research accounting issues				4.00	38.9%	179.44		179.44
ACC 004	Maintain general ledger	314.00	16,668.24						16,668.24
ACC 008	Analyze financial results	2.00	1,466.67						1,466.67
ACC 009	Monitor accounting and reporting standards	13.75	3,138.76	7,000.00	59.00	38.9%	2,140.42		12,279.18
ACC 018	Intercompany billing administration				453.25	40.8%	8,502.17		8,502.17
		329.75	21,273.67	7,000.00	516.25		10,822.03	0.00	39,095.70
ADM	**Administrative**								
ADM 006	Assist on rate cases	380.00	29,792.11						29,792.11
ADM 007	Corporate risk review				17.50	40.8%	4,277.96		4,277.96
ADM 011	Telephone charges			3,056.32					3,056.32
ADM 012	Rent - ASB Tower (formerly Pacific Tower)			54,667.90					54,667.90
ADM 013	Supplies			2,000.00					2,000.00
ADM 014	Rent - Central Pacific			41,194.25					41,194.25
ADM 112	Sarbanes-Oxley Section 302	2.00	271.46						271.46
		382.00	30,063.57	100,918.47	17.50		4,277.96	0.00	135,260.00
ANN	**Annual meeting**								
ANN 001	Annual shareholder meeting planning & coordination				105.25	38.6%	4,996.59	4,605.91	9,602.50
		0.00	0.00	0.00	105.25		4,996.59	4,605.91	9,602.50
AUD	**Audits**								
AUD 005	Audit Committee meeting attendance					62.1%		220.47	220.47
		0.00	0.00	0.00	0.00		0.00	220.47	220.47
BOD	**Board of Directors**								
BOD 001	Board of Directors meetings	314.75	18,013.77	282.79					18,296.56
BOD 002	Attendance (presentations)	42.50	30,679.35						30,679.35
BOD 005	Misc. board matters	2.30	1,152.36	380.96					1,533.32
		359.55	49,845.48	663.75	0.00		0.00	0.00	50,509.23
BUD	**Budgets**								
BUD 001	Preparation	0.25	19.99						19.99
		0.25	19.99	0.00	0.00		0.00	0.00	19.99
CAS	**Cash Management**								
CAS 006	Cash disbursements (wire confirmations)	5.67	249.98						249.98
		5.67	249.98	0.00	0.00		0.00	0.00	249.98

HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004 Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004 Shared Labor Hours	2004 Allocatio Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual	
COM	**Community Relations**									
COM 001	Media relations and communications	1.50	1,114.14						1,114.14	
		1.50	1,114.14	0.00	0.00		0.00	0.00	1,114.14	
CON	**Consulting - general**									
CON 002	Meetings	24.25	17,828.16						17,828.16	
CON 004	Other	28.50	20,464.24	2,081.27					22,545.51	
		52.75	38,292.40	2,081.27	0.00		0.00	0.00	40,373.67	
FIN	**Financing**									
FIN 001	Debt financing planning and coordination	17.75	2,386.48	109.37					2,495.85	
FIN 002	Debt financing due diligence	11.75	1,452.88						1,452.88	
FIN 100	Stock split				18.75	38.6%	1,436.75	107,792.21	109,228.96	
		29.50	3,839.36	109.37	18.75		1,436.75	107,792.21	113,177.69	
HUM	**Human Resources**									
HUM 001	Benefits consulting services	1.00	232.48		2.75	39.9%	253.45		485.93	
HUM 002	Compensation consulting services	1.75	399.63		0.50	41.2%	47.04		446.67	
HUM 008	Code of Conduct development and administrative assistance				0.75	39.9%	68.34		68.34	
HUM 009	Code of Conduct review				5.25	39.9%	484.92	6,162.08	6,647.00	
HUM 010	Compensation committee meetings				135.50	41.2%	8,741.55		8,741.55	
HUM 011	Long-term incentive plan (LTIP)	1.25	79.09		26.50	6.6%	138.28		217.37	(1)
HUM 012	Executive incentive compensation plan (EICP)				56.00	25.5%	1,205.36		1,205.36	(2)
HUM 013	Stock options with dividend equivalents	22.00	1,195.61		186.50	30.8%	5,071.63	4,448.53	10,715.77	(3)
HUM 014	Stock options	16.00	712.50						712.50	(4)
HUM 015	Executives deferred compensation				7.25	71.4%	352.49	72.03	424.52	(5)
		42.00	2,619.31	0.00	421.00		16,363.06	10,682.64	29,665.01	
INT	**Internet**									
INT 001	Frontbridge (spam filtering)			7,805.00		90.0%		3,664.67	11,469.67	
INT 002	Firewall services					32.0%		29,661.42	29,661.42	
INT 003	Internet services					33.0%		3,317.56	3,317.56	
INT 004	Shared internet connection					58.6%		24,877.98	24,877.98	
INT 005	File Transfer Protocol (FTP) server					90.0%		312.50	312.50	
INT 006	Disaster recovery (ISDN line)			2,129.43					2,129.43	
		0.00	0.00	9,934.43	0.00		0.00	61,834.13	71,768.56	

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HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004 Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004 Shared Labor Hours	2004 Allocatio Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual
INV	**Investor Relations**								
INV 001	Analyst/media communications				134.50	38.6%	5,132.57		5,132.57
INV 003	Fact sheet				4.50	38.6%	143.77		143.77
INV 004	Financial mailing list				38.00	38.6%	817.24	3,527.92	4,345.16
INV 005	Financial news releases			98.80	184.50	38.6%	7,892.15	3,462.14	11,453.09
INV 006	Group analyst meetings				768.50	38.6%	47,012.34	103,498.03	150,510.37
INV 007	HEI stock - share forecast				4.00	38.6%	86.45		86.45
INV 008	Investor base/stockholder monitoring				18.50	38.6%	709.22	15,142.01	15,851.23
INV 009	Investor relations planning				68.00	38.6%	1,567.72	653.29	2,221.01
INV 011	National Association of Investors Corporation (NAIC)					38.6%		802.88	802.88
INV 012	One-on-one meetings/visits with analysts				82.00	38.6%	9,443.31		9,443.31
INV 013	Other investor relations activities				118.00	38.6%	4,094.40	30,130.20	34,224.60
INV 015	Retail/broker/shareholder communications				33.50	38.6%	1,266.37		1,266.37
INV 018	Statistical supplement				18.50	38.6%	541.20		541.20
INV 019	Surveys	0.50	34.39		10.50	44.1%	342.10		376.49
INV 020	Teleconferencing				14.00	38.6%	1,072.05		1,072.05
		0.50	34.39	98.80	1,497.00		80,120.89	157,216.47	237,470.55
PEN	**Pension plan**								
PEN 005	HEIRS	2.60	145.63		426.20	45.2%	12,000.37	15,087.63	27,233.63
PEN 007	HEI Retirement Plan	6.50	364.07		7.25	72.8%	402.95		767.02
PEN 009	Master pension trust				773.00	67.7%	84,667.62	1,559.20	86,226.82
PEN 022	Supplemental Exec. Retirement plan					50.0%		1,495.00	1,495.00
PEN 026	OPEB funded plans/trusts				646.50	68.5%	39,275.55	1,577.71	40,853.26
PEN 028	HECO OPEB Plan	43.50	2,484.61		84.50	68.5%	3,606.64		6,091.25
PEN 030	HEI postretirement electric discount trust	1.50	119.94		1.00	27.2%	21.26		141.20
		54.10	3,114.25	0.00	1,940.45		139,974.39	19,719.54	162,808.18
RPT	**Reports**								
RPT 001	10K preparation	1.00	52.34		306.75	38.9%	11,254.14	15,425.52	26,732.00
RPT 011	10Q preparation	23.71	1,738.99	904.80	859.25	38.9%	31,036.36	32,179.49	65,859.64
RPT 015	10Q printing and mailing					36.3%		313.82	313.82
RPT 021	8K preparation	25.00	2,237.16	11,305.59	139.75	38.9%	3,569.31	6,693.38	23,805.44
RPT 041	Proxy preparation				71.70	38.6%	3,521.43	17,085.89	20,607.32
RPT 045	Proxy printing and mailing					35.9%		89,046.27	89,046.27
RPT 051	Annual report preparation	75.00	4,411.95		985.80	38.9%	35,412.28	121,829.05	161,653.28
RPT 055	Annual report printing and mailing					36.3%		52,386.97	52,386.97
RPT 098	Financial Reporting-Sarbanes Oxley Related Charges					38.9%		53,081.96	53,081.96
		124.71	8,440.44	12,210.39	2,363.25		84,793.52	388,042.35	493,486.70

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HECO
EXCLUDING INCENTIVE COMPENSATION

Activity code	ACTIVITY CODE DESCRIPTIONS	Direct Charges-2004 Direct Labor Hours	Direct Labor Dollars	Direct Nonlabor Dollars	Shared Charges-2004 Shared Labor Hours	2004 Allocatio Factor	Shared Labor Dollars	Shared Nonlabor Dollars	2004 Actual
STO	**Stock Transfer activities**								
STO 001	Preferred stock dividend payments	14.55	785.28						785.28
STO 003	Form 1099 (for preferred stockholders)	3.00	141.96						141.96
STO 004	Preferred stockholder database maintenance	17.30	755.36						755.36
STO 005	Other preferred stock communications	1.25	55.70						55.70
STO 006	Preferred stock transfer administrative activities	50.90	2,789.06	152.58					2,941.64
STO 011	Common stock dividend payments				61.80	35.9%	1,150.13	1,826.58	2,976.71
STO 012	HEI dividend reinvestment program administration				2,769.85	35.9%	47,281.69	36,526.76	83,808.45
STO 013	Form 1099 Dividends				25.50	35.9%	440.06	771.37	1,211.43
STO 014	Common stockholder database maintenance				1,197.80	35.9%	18,703.95	433.58	19,137.53
STO 015	Other common stock communications				1,950.75	35.9%	34,124.46		34,124.46
STO 016	Common stock transfer administrative activities				2,309.65	35.9%	46,065.41	12,330.69	58,396.10
STO 018	Stock transfer system				150.30	35.9%	2,576.77	47,041.02	49,617.79
STO 019	Stock transfer division expenses					35.9%		39,494.44	39,494.44
STO 020	Stock transfer division miscellaneous income					35.9%		(31,909.43)	(31,909.43)
		87.00	4,527.36	152.58	8,465.65		150,342.47	106,515.01	261,537.42
TAX	**Tax**								
TAX 001	Tax return preparation	290.18	15,513.76		227.50	36.3%	4,684.83	5,671.84	25,870.43
TAX 002	Tax return review	80.00	7,955.58		57.50	36.3%	2,615.20		10,570.78
TAX 003	Tax and financial planning	156.25	18,706.43		42.50	36.3%	2,069.38		20,775.81
TAX 006	Tax research	169.01	9,888.26	469.87	10.00	36.3%	164.03		10,522.16
TAX 007	Tax accrual review	242.50	16,837.42		21.00	36.3%	755.71		17,593.13
TAX 008	Tax compliance software implementation	48.25	2,631.06		2.00	36.3%	39.65		2,670.71
TAX 009	Assistance on the IRS/State examination	168.68	12,532.09		169.75	36.4%	5,302.17		17,834.26
TAX 010	Information returns	83.25	4,451.80						4,451.80
TAX 011	IRS/Dept. of Taxation correspondence	26.25	1,178.07						1,178.07
TAX 012	Estimated tax computation	16.20	1,038.12		3.00	36.3%	58.84		1,096.96
TAX 013	General excise tax returns	3.50	222.13						222.13
TAX 014	Payroll tax withholding	78.25	3,728.20						3,728.20
TAX 017	Other tax matters	36.25	2,273.36	427.82					2,701.18
TAX 018	Executive payroll issues	11.75	1,042.97						1,042.97
TAX 019	Taxes-Sarbanes Oxley Related Charges	240.00	16,086.57						16,086.57
TAX 020	Tax Depreciation	336.50	17,942.01						17,942.01
		1,986.82	132,027.83	897.69	533.25		15,689.81	5,671.84	154,287.17
	Total of all activity codes	3,456.10	295,462.17	134,066.75	15,878.35		508,817.47	862,300.57	1,800,646.96
Less other costs related to incentive compensation to be consistent with HECO-1310									
HUM 011	Long-term incentive plan (LTIP)								(217.37) (1)
HUM 012	Executive incentive compensation plan (EICP)								(1,205.36) (2)
HUM 013	Stock options with dividend equivalents								(10,715.77) (3)
HUM 014	Stock options								(712.50) (4)
HUM 015	Executives deferred compensation								(424.52) (5)
	Adjusted total								1,787,371.44

HECO Charges

Shared charges

(Revised 3-31-05)

	Activity Code	Workorder #	2004
ANNUAL MEETING ACTIVITIES			
Annual meeting expenses	ANN001	CR000047	2,318.25
Annual meeting room set-up	ANN001	FA000224	1,161.86
Other annual meeting charges	ANN001	AD000684	3,301.41
Harry Arakaki work for HEI	ANN001	AD001377	279.09
Total annual meeting charges			7,060.61
2004 HECO allocation factor			38.6%
Total shared annual meeting charges to HECO			2,725.40
INVESTOR RELATIONS ACTIVITIES			
News releases - printing services	INV004	IT000293	387.73
Digital printing services	INV006	IT000323	461.42
Group analyst meeting charges	INV006	AD000201	19,964.11
Group analyst meeting meals	INV006	AD000202	597.51
Other investor relations charges	INV013	AD000196	214.09
Total investor relations charges			21,624.86
2004 HECO allocation factor			38.6%
Total shared investor relations charges to HECO			8,347.20
PENSION PLAN ACTIVITIES			
Master Pension Trust related charges	PEN009	AD000578	1,918.85
Total Master Pension Trust charges			1,918.85
2004 HECO allocation factor			67.7%
Total shared Master Pension Trust charges to HECO			1,299.06
OPEB funded plans/trusts charges	PEN026	AD000578	1,918.86
Total OPEB funded plans/trusts charges			1,918.86
2004 HECO allocation factor			68.5%
Total shared OPEB funded plans/trusts charges to HECO			1,314.42
REPORTING ACTIVITIES			
10-K services	RPT001	AD000132	52.01
2004 HECO allocation factor			38.9%
Total shared 10-K charges to HECO			20.23
10-Q printing services	RPT015	IT000294	864.50
2004 HECO allocation factor			36.3%
Total shared 10-Q charges to HECO			313.81
Proxy Statement charges	RPT041	AD000164	12,196.42
Total proxy charges			12,196.42
2004 HECO allocation factor			38.6%
Total shared proxy charges to HECO			4,707.82
Annual report charges	RPT051	CR000048	2,622.48
Total annual report charges			2,622.48
2004 HECO allocation factor			38.9%
Total shared annual report charges to HECO			1,020.14
STOCK TRANSFER ACTIVITIES			
DRIP statements charges	STO012	IT000299	20.20
Shareholder Services charges	STO016	IT000295	351.92
Stock Transfer charges	STO016	AD000140	219.76
Information system charges	STO019	IT000229/255	16,644.00
Total stock transfer charges			17,235.88
2004 HECO allocation factor			35.9%

CA-IR-257

Ref: HECO-1314 (A&G Expense Transferred).

Please provide a copy of the original and updated KPMG studies.

HECO Response:

The Administrative Transfer Study prepared by KPMG in December 1996 and the

KPMG

The Global Leader

HAWAIIAN ELECTRIC COMPANY, INC.

Administrative Transfer Study

December 1996

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SECTION 1

BACKGROUND

The subject of the transfers of administrative and general (administrative) costs to construction has been the topic of discussion in various rate cases of Hawaiian Electric Company, Inc. (HECO) (i.e., Public Utilities Commission of the State of Hawaii (PUC) Docket Nos. 7700 and 7766), Hawaii Electric Light Company, Inc. (HELCO) (i.e., PUC Docket No. 7764), and Maui Electric Company, Ltd. (MECO) (i.e., PUC Docket Nos. 7000 and 94-0345). This report is intended to address concerns raised in those dockets and Decision and Orders and sets forth the methodology to be used by HECO in determining the administrative costs to transfer to construction.

In the various rate case dockets cited above, the Consumer Advocate and HECO disagreed on the administrative costs transferred to construction. The disagreements were caused by differing interpretations and applications of the utility plant instructions contained in the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts (USOA) For Classes A and B Electric Utilities. The differences specifically related to utility plant instruction No. 4, part B (relating to overhead construction costs) which states that:

> "As far as practicable, the determination of payroll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted."

NARUC's interpretation (NARUC Interpretation No. 60) of its instruction cited above states that:

> " . . . In general, it is believed that the incremental cost basis is the preferred method of determining amounts of administrative and general expenses which should be capitalized. Under this method, only the costs specifically incurred for construction - costs which would not be incurred if construction were not undertaken - are chargeable to construction. . . ."

Under HECO's current methodology, time card distributions are utilized to charge administrative costs to construction when feasible or cost effective. When this is not feasible or cost effective, the ratio of total plant labor to total labor (excluding administrative labor eligible for capitalization) is used to allocate administrative costs to construction.

In its Decision and Order No. 13704, in Docket No. 7700 (dated December 28, 1994), the PUC stated that it agreed with HECO's interpretation and application of NARUC's utility plant instruction No. 4, part B in that only those incremental administrative costs directly associated with physical construction activities may be transferred to construction. The PUC, however, questioned the methodology used by HECO to transfer administrative costs to construction and required, for future rate cases, that HECO conduct a time study or periodic survey to better identify and quantify employee participation in tasks that support the construction function. In Docket No. 7766, HECO agreed to prepare a formal time study addressing an alternate methodology to determine the administrative transfers to construction and engaged KPMG Peat Marwick LLP (KPMG) to perform this time study.

SECTION 2

STUDY OBJECTIVES, SCOPE AND APPROACH

OBJECTIVES

HECO and its subsidiaries, HELCO and MECO, engaged KPMG to perform a time study to address the concerns expressed by the PUC regarding the transfers of administrative costs to construction. In its Decision and Order No. 13704, in Docket No. 7700 (dated December 28,

following two issues related to administrative transfers to construction:

1. Provide the PUC with the criteria or justification for the inclusion of particular tasks directly related to construction.

2. Conduct a time study or periodic survey to better identify and quantify employee participation in tasks that support the construction function.

purposes of the study. This phase of the study is discussed in further detail in Section 4, Development of Methodology to Determine Administrative Costs to Transfer to Construction.

Phase II - Determine methods of collection for current direct and indirect costs and consumption information (i.e., the basis for allocating costs to activities).

Using the construction related activity definition established in Phase I, the administrative cost pools subject to allocation to construction were determined and the related drivers of those costs for the construction related activities were identified. Through discussions with HECO personnel, the sources from which the administrative cost and consumption information will be accumulated for the study were identified. A time study was conducted of the construction related activities performed by administrative employees charging the 920.00 account utilizing job activity questionnaires (i.e., time sheets and workload surveys). This phase of the study is discussed in further detail in Section 3, Overview of HECO's Organization and Current Administrative Transfer Methodology, and Section 4, Development of Methodology to Determine Administrative Costs to Transfer to Construction.

Phase III - Develop administrative transfer methodology.

Using the information obtained in the first two phases, an administrative transfer methodology was developed to determine the transfer of administrative costs to construction. This phase of the study is discussed in further detail in Section 4, Development of Methodology to Determine Administrative Costs to Transfer to Construction, and Section 5, Results and Summary of Cost Information.

Phase IV - Analyze results and summarize cost information in a report.

The results of the time study were analyzed and have been summarized in Section 5, Results and Summary of Cost Information.

SECTION 3

OVERVIEW OF HECO'S ORGANIZATION AND CURRENT ADMINISTRATIVE TRANSFER METHODOLOGY

HECO (Company) is an operating public utility and the largest electric utility subsidiary of Hawaiian Electric Industries, Inc. (HEI). The Company is in the business of generating, purchasing, transmitting, distributing and selling electric energy on the island of Oahu and is regulated by the PUC. Currently, it provides electricity to approximately 270,000 residential, commercial, and industrial accounts. HECO's personnel report to seven vice presidents and the president. The company organizational structure contains 32 departments which are further segregated into responsibility areas.

In rate making proceedings, administrative costs are normally categorized into the following five major account groups and related functional accounts:

Major Account Groups	Account Code	Functional Accounts
1. Administrative	92000	Administrative and General Salaries
	92100	Office Supplies and Expenses
	92201	Administrative Expenses Transferred to Construction - Credit
	92202	Administrative Expenses Transferred to Other Than Construction - Credit
2. Outside Services	92301	Outside Legal Services
	92302	Other Outside Services
	92303	Services from Associated Companies
3. Insurance	92400	Property Insurance
	92501	Injuries and Damages - Employees
	92502	Injuries and Damages - Public

Major Account Groups	Account Code	Functional Accounts
4. Employee Benefits	92600	Employee Benefits - Flex Credits
	92601	Employee Pensions - Nonfunded
	92602	Employee Benefits - Dental Plan Premium
	92603	Employee Pensions-Funded
	92604	Employee Group Life Insurance
	92605	Employee Group Medical and Hospital Insurance
	92606	Other Employee Benefits
	92607	Employee Vision Plan
	92608	Long-Term Disability Plan
	92609	Postretirement Benefits
	92690	Employee Benefits Expenses Transferred to Construction - Credit
	92691	Employee Benefits Expenses Transferred to Other Than Construction - Credit
5. Miscellaneous Accounts	92800	Regulatory Commission Expenses
	93010	Institutional or Goodwill Advertising
	93021	Community Service Activities
	93022	Company Memberships Expense
	93023	Conventions and Meetings Expense
	93024	Research and Development Expense
	93025	Preferred Stock and Long-Term Debt Expenses
	93027	Stockholders' Meetings and Annual Reports
	93028	Directors' Fees and Expenses
	93029	Miscellaneous General Expenses - Abandoned Capital Projects
	93100	Rents
	93200	Maintenance of General Plant

Under HECO's current methodology, time card distributions are used to charge administrative costs to construction when feasible or cost effective. That is, the labor costs of those employees who work on specific construction projects for constant periods of time and who can easily identify the amount of time spent on construction projects are charged directly to construction.

For those employees who are not assigned to work on specific construction projects but whose job activities otherwise have a definite relation to construction, HECO currently allocates the associated labor costs to construction based on the ratio of total plant labor to total labor, excluding administrative labor eligible for capitalization. The use of this ratio was primarily necessitated by the nature of these employees' job activities. The job activities of these employees involve the processing of large volumes of transactions and other supporting functions related to construction as well as non-construction projects of the Company. Thus, it is not only difficult but also cost ineffective and inefficient for these employees to directly charge their labor costs to construction. That is, the costs of the additional time that would be spent by the employees tracking the amount of time that they spend on each construction related task outweighs the benefits of having their labor costs directly charged to construction.

Non-labor costs specifically related to construction activities are directly charged to the respective construction projects. Administrative non-labor costs such as office supplies and expenses which are not associated with specific construction projects but which have a definite relation to construction are allocated to construction based on the same methodology and ratios used to allocate administrative labor costs to construction.

As mentioned in Section 1, Background, the PUC agreed with HECO's interpretation and application of the NARUC utility plant instruction No. 4, part B in that only those incremental administrative costs directly associated with physical construction activities may be transferred to construction. The PUC, however, questioned the methodology used by HECO to transfer administrative costs to construction and required, for future rate cases, that HECO conduct a time study or periodic survey to better identify and quantify employee participation in tasks that support the construction function. HECO has thus engaged KPMG to perform a time study addressing an alternate methodology to determine administrative transfers to construction.

SECTION 4

DEVELOPMENT OF METHODOLOGY TO DETERMINE ADMINISTRATIVE COSTS TO TRANSFER TO CONSTRUCTION

The development of the methodology to determine the administrative costs to transfer to construction involved the establishment of the construction related activity definition, the identification of the employees subject to the time study, and the determination of the collection methods of the cost and consumption information required for the study.

ESTABLISHMENT OF CONSTRUCTION RELATED ACTIVITY DEFINITION

Authoritative guidelines relating to administrative transfers are provided in the NARUC USOA for Classes A and B Electric Utilities. Specifically, utility plant instruction No. 4 of the NARUC USOA provides that:

"A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

B. As far as practicable, the determination of payroll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

C. The records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount

of each overhead expenditure charged to each construction work order and to each utility plant account, and the basis of distribution of such costs."

NARUC's interpretation (NARUC Interpretation No. 60) of its instruction cited above states that:

" . . . In general, it is believed that the incremental cost basis is the preferred method of determining amounts of administrative and general expenses which should be capitalized. Under this method, only the costs specifically incurred for construction - costs which would not be incurred if construction were not undertaken - are chargeable to construction. . . ."

Based on the authoritative guidance cited above, KPMG established the following construction related activity definition to serve as the criteria or justification to be used in determining whether a particular task is directly related to construction for the purposes of the study.

Administrative and general labor costs are charged to the administrative and general salaries account (920.00). Associated non-labor administrative and general expenses are charged to the office supplies and expense account (921.00). A portion of the expenses relating to certain of the employees who charge these accounts is allocable to the cost of construction. This allocation is based upon the relationship of time spent on construction related tasks to the total available time of these particular employees.

The incremental cost principle is used to determine which of these employees' labor and associated costs are to be included in the allocation process. Under this principle, only costs associated with employees whose positions are necessitated by the construction program are includible in the allocation. In other words, if the employee or manager position is considered to be necessary regardless of the construction program, the costs related to that position would not be includible in the allocation. For example, the President's labor costs would not be considered allocable to construction, since the position would be required even if no construction activity occurred.

Once a position is deemed to be construction related, the construction related tasks for that respective position are defined to include only those tasks that have a definite and direct relationship to the physical construction of plant facilities. These tasks must also have an initial and direct relationship to the physical construction. For example,

an accounting clerk's task of processing a contractor invoice for payment would be considered to have an initial and direct relationship to physical construction. On the other hand, the accounting manager that supervises the accounting clerk would not be considered to have an initial and direct relationship to the physical construction.

Based on the definition stated above, an activity must meet both of the following requirements in order to be considered construction related:

1. The employee's position satisfies the incremental cost principle, and

2. The tasks performed by the employee have an initial, definite, and direct relationship to the physical construction of plant facilities.

IDENTIFICATION OF EMPLOYEES SUBJECT TO TIME STUDY AND DEFINITION OF CONSTRUCTION RELATED ACTIVITIES

Interviews were conducted with representatives of the responsibility areas; and questionnaires completed by each responsibility area position that charges the 920.00 and 921.00 accounts were reviewed to obtain an understanding of the construction related activities performed. A listing of all responsibility area positions charging the 920.00 account is included in **Exhibit I**. The responsibility areas interviewed included:

Department	Responsibility Area
1. General Accounting	Administrative Corporate Accounting Cost Accounting Taxes & Property Accounting
2. Engineering & Project Management	Administrative Land & Rights of Way Survey
3. Customer Service	Customer Assistance Center Payment Processing & Support Center

Department	Responsibility Area
4. Information Services	Administrative Computer and Office Services Systems and Services Development Mailing Publishing & Records Services Network Services
5. Energy Services	Forecasts Research and Evaluation Pricing
6. Facilities	Buildings & Grounds Facilities Planning Security
7. Environmental	Administrative Air Quality & Emissions Analytical Services Water and Hazardous Materials
8. Financial Services	Administrative Capital Budgets Financial Analysis Risk Management Securities Treasury
9. Industrial Relations	Administrative Labor Relations & Wage Administration Workers' Compensation & Personnel Administration
10. Power Supply Services	Administrative Technical Services Fuels Power Purchase

Department	Responsibility Area
11. Support Services	Administrative
	Facilities Maintenance
	Purchasing
12. Planning & Engineering	Administrative
	Generation Planning
	Clerical
	Power Plant Project Management
	Power Plant Mechanical Engineering
	Integrated Resource Planning
13. Senior Management	VP-Energy Delivery
	VP-Regulatory Affairs
	Financial VP/Treasurer's Office
	VP-General Counsel & Government Relation's Office
	VP-Corporate Excellence's Office
	VP-Power Supply
	VP-Customer Operations
	President's Office
14. Other	Management Accounting
	Compensation
	Employment & Human Resource Development
	Organizational Development & Continuous Improvement

and direct and/or initial and direct relationship to physical construction be classified as construction related. As a result of our interviews and reviews of the questionnaires, certain responsibility area positions were found to not meet the incremental cost principle, primarily due to their management status and/or a determination that the tasks performed do not have an initial, definite, and direct relationship to the physical construction of plant facilities. To validate the results of our interviews and reviews of the questionnaires completed by these responsibility area positions, we also reviewed the job descriptions for each of these positions. Based on the results of the interviews, questionnaires and job description reviews, these responsibility area positions were excluded from the time study and their associated salaries were not subjected to allocation. Listings of the responsibility area positions which were and were not included in the time study and allocation are included in **Exhibits II and III**, respectively.

Detailed discussions were held with those individuals included in the time study to confirm their understanding of the construction related activity definition and to further define their specific job tasks as construction related versus non-construction related. The tasks performed by these responsibility area positions which conform to the definition of construction related tasks are as follows:

Function	Construction Related Task
Accounts Payable	Processing invoices which generate the respective payments for the construction costs of plant facilities.
Job Costing	Maintaining the job cost system, which is the construction accounting system for the Company, and setting up the work orders required to collect construction costs in the job cost system.
Purchasing	The purchase of materials and services used for construction.
Research and/or acquisition of land	The acquisition of land upon which the Company's facilities are constructed.
Recruitment, benefits, training	The hiring, training, etc. of employees who are directly involved in the physical construction of plant facilities.

DETERMINATION OF COLLECTION METHODS OF COSTS AND CONSUMPTION INFORMATION

The cost information required for the study consisted of administrative salaries expense, office supplies and expenses, and services from associated companies. This information was obtained from the Company's payroll reports and general ledger.

For the purposes of this study, the total costs to be allocated to activities (i.e., construction related and non-construction related) were classified into "cost pools." Cost pools are the major components of costs incurred by an organization such as labor, vehicles, direct materials or overhead costs. For the purposes of this study, the cost pools were defined as administrative labor costs (i.e., time study participants' salaries) charged to the 920.00 account and administrative non-labor costs charged to the 921.00 account. The administrative labor cost pools include both productive and non-productive time.

Once the activities and cost pools to be allocated were identified, the "cost pool drivers" were determined. A cost pool driver is a unit of measure used to allocate cost pools to activities. The unit of measure should be the best indicator of the rate of cost consumption, or resource usage of an activity. For the purposes of this study, all of the cost pool drivers were defined as direct labor hours. See **Exhibit IV** for the Cost Pool / Driver Report and the Reconciliation of General Ledger to Costs for Allocation Report for the time study period and validating time study period.

The following cost pools and cost pool drivers were identified for this study:

Cost Pool Drivers	Cost Pools
Accounting Clerk II salary (2 positions)	Direct Hours*
Accounting Clerk III salary (2 positions)	Direct Hours*
Associate Plant Accountant salary	Direct Hours*
Accounts Payable & Disbursement Clerk salary	Direct Hours*
Buyer salary (4 positions)	Direct Hours*
Employment & Human Resource Development Consultant salary (2 positions)	Direct Hours*
Employment & Human Resource Development Coordinator salary	Direct Hours*
Job Accounting Clerk salary	Direct Hours
Job Accountant salary	Direct Hours
Land Agent salary (4 positions)	Direct Hours
Land Assistant salary	Direct Hours
Plant Accounting Clerk	Direct Hours*
Property Accountant salary	Direct Hours*
Purchasing Clerk salary (3 positions)	Direct Hours*
Senior Clerk salary	Direct Hours*

* Variances from the use of direct hours are explained in **Exhibit V**.

The aforementioned cost pool drivers were used to allocate the salary costs of the aforementioned individuals proportionate to the number of labor hours devoted to each activity (i.e., construction and non-construction). See **Exhibit VI** for the allocations of the aforementioned individuals' salary costs between construction and non-construction activities for the time study and validating time study period. Variances from the use of direct hours as noted with "*" above are explained in **Exhibit V**.

For the purposes of this study, direct productive labor hours were identified as the basis for allocating applicable administrative salaries to construction. Time sheets were utilized to track the hours worked on construction related activities by each time study participant. All individuals participating in the time study were instructed on the completion of the time sheets. See **Appendix A** for a copy of the timesheet and related instructions.

The time study was conducted for the one month period of June 1996. A validating time study was conducted for the month of July 1996 to validate the results of the previous time study period. See Section 5, Results and Summary of Cost Information, for the results of the time studies.

During the time study and validating time study period, each participant was required to prepare weekly time sheets documenting the description of the construction related and/or non-construction related activities performed each day and the estimated amount of time that he (she) spent on each activity. Note that any construction related activities that were directly charged to construction (i.e., specific projects) were separately identified on the time sheets and excluded from the calculation of the administrative transfer rate for the 920.00 account and included in the calculation of the administrative transfer rate for the 921.00 account (See Section 5, Results and Summary of Cost Information for further discussion). Upon completion, the time sheets were submitted to the individual's supervisor for a reasonableness review. The completed time sheets were collected on a weekly basis and, as necessary, KPMG reviewed the time sheets with the individual to clarify and confirm our understanding of the information on the time sheets. The time allocation information obtained from these time sheets served as the basis for allocating the individual's labor costs to construction. See Section 5, Results and Summary of Cost Information, for the results of the time studies and discussion of the administrative transfer methodology.

SECTION 5

RESULTS AND SUMMARY OF COST INFORMATION

Based upon the time allocation information obtained from the time sheets, we determined that the administrative costs in the 920.00 and 921.00 accounts allocable to construction for the time study period and validating time study period are as follows (see **Exhibit VII** for the calculation of administrative costs allocable to construction for the 920.00 and 921.00 accounts):

Administrative Costs Allocable to Construction

		For the Time Study Period Ended	
Account No.	Account Description	6/30/96	7/31/96
920.00	Administrative and General Salaries	$ 35,921	$ 36,219
921.00	Office Supplies and Expense	$ 28,307	$ 25,169

The construction related administrative costs presented above were used to determine administrative transfer rates for the 920.00 and 921.00 accounts for the one month time study period ended June 30, 1996 and the one month validating time study period ended July 31, 1996. The administrative transfer rates determined for each account for the time study period and the validating time study period are presented below:

Administrative Transfer Rate (% of Total Cost Pool)

		For the Time Study Period Ended	
Account No.	Account Description	6/30/96	7/31/96
920.00	Administrative and General Salaries	41%	36%
921.00	Office Supplies and Expense	6%	5%

Based upon our inquiries into the causes for the variance in the 920.00 administrative transfer rates between the time study and validating time study periods, we concluded that the average of the administrative transfer rate of 41% for the time study period ended June 30, 1996 and 36% for the validating time study period ended July 31, 1996 is more representative of a typical month at HECO. As such, the administrative transfer rate of 39% may be applied against the total 920.00 labor costs of the time study participants to determine the amount to be transferred to construction. The 921.00 administrative transfer rate of 6% for the time study period ended June 30, 1996 may be applied against the total 921.00 office supplies and expense to determine the amount to be transferred to construction.

The administrative transfer rate for the 920.00 account was calculated as follows:

1. For each time study participant, the ratio of direct labor hours spent on construction related activities (excluding labor hours directly charged to specific construction projects) as documented on the time sheets by the time study participant, to the total hours worked by the participant (excluding labor hours directly charged to specific construction projects and nonproductive hours such as holiday, sick, vacation, military leave, jury duty, etc.) was applied against the respective individual's salary and/or wages during the corresponding period (reduced for labor costs directly charged to construction) to determine the construction related portion of the participant's 920.00 labor costs for the time study period;

2. The construction related 920.00 labor costs determined in step 1 above for each time study participant were summarized for all participants to determine the total construction related administrative costs in the 920.00 account for the time study period; and

3. The total construction related 920.00 administrative costs determined in step 2 above was divided by the total 920.00 labor costs of the time study participants for the corresponding period to derive the transfer rate (excluding labor costs directly charged to construction) for the time study period.

Note that the calculation of the construction related 920.00 administrative costs in step 1 above takes into consideration that the allocable labor costs of an employee include not only the salary and wages paid for the productive hours worked by the employee but also the salary and wages paid for the employee's non-productive hours (e.g., holiday, vacation, sick, military leave, jury duty, etc.). See **Exhibit VII** for the calculation of the administrative transfer rate for the 920.00 account for the time study period and validating time study period.

The administrative transfer rate for the 921.00 account is calculated by dividing the direct labor hours spent on construction related activities (including labor hours directly charged to specific

construction projects) as documented on the time sheets by the time study participants by the total productive labor hours of all administrative employees who charge the 920.00 account (including labor hours directly charged to specific construction projects and excluding nonproductive hours such as holiday, sick, vacation, military leave, jury duty, etc.).

Note that the calculation of the 921.00 administrative transfer rate above assumes that office supplies and expenses are costs that are not associated with specific construction projects but

[redacted]

as non-construction related purposes at a rate proportional to labor hour(s) related to each task. The calculation of the administrative transfer rate for the 921.00 account for the time study and validating time study periods is presented in **Exhibit VII**.

10. Administrative (Information Services)
11. Computer and Office Services
12. Systems and Services Development
13. Mailing
14. Publishing & Records Services
15. Network Services
16. Forecasts
17. Research and Evaluation
18. Pricing
19. Buildings & Grounds
20. Facilities Planning
21. Security
22. Administrative (Environmental)
23. Air Quality & Emissions
24. Analytical Services
25. Water and Hazardous Materials
26. Administrative (Financial Services)
27. Capital Budgets
28. Financial Analysis
29. Risk Management
30. Securities
31. Treasury
32. Administrative (Industrial Relations)
33. Labor Relations & Wage Administration
34. Workers' Compensation & Personnel Administration
35. Administrative (Power Supply)
36. Technical Services
37. Fuels
38. Power Purchase
39. Administrative (Support Services)
40. Facilities Maintenance
41. Purchasing
42. Administrative (Planning & Engineering)
43. Generation Planning
44. Clerical (Planning & Engineering)
45. Power Plant Project Management
46. Power Plant Mechanical Engineering
47. Integrated Resource Planning
48. VP-Energy Delivery

49. VP-Regulatory Affairs
50. Financial VP/Treasurer's Office
51. VP-General Counsel & Government Relation's Office
52. VP-Corporate Excellence's Office
53. VP-Power Supply
54. VP-Customer Operations
55. President's Office
56. Management Accounting
57. Compensation
58. Employment & Human Resource Development
59. Organizational Development & Continuous Improvement
60. Internal Audit
61. Legal
62. Government Relations
63. Regulatory Affairs
64. Telecommunications
65. Corporate Communications

- The costs associated with the aforementioned responsibility areas are properly charged to the 920.00 and/or 921.00 accounts;

- The President, Vice Presidents, Managers, Directors, Administrators, and Supervisors are all positions within the responsibility areas whose associated costs are charged to the 920.00 and 921.00 accounts that do not satisfy the incremental cost principle (i.e., if there were no construction activities, these positions and the associated labor costs would still exist). Thus, the labor costs charged to the 920.00 account for these positions are allocable to non-construction related accounts;

- The information provided by the time study participants on the time sheets and employee workload surveys are an accurate and true representation of each participant's time;

- The time spent by each time study participant performing construction related activities is representative of the average construction related efforts throughout the year;

- For the responsibility areas included in the time study, the costs in the 921.00 account are consumed for construction related as well as non-construction related purposes at a rate proportional to labor hour(s) related to each task; and

- The information on the reports (e.g., payroll reports, general ledger, etc.) provided by HECO and utilized in the calculations of the administrative costs allocable to construction and the administrative transfer rates are an accurate and correct representation of the payroll expense, administrative expenses, etc. for the time study period and validating time study period.

The administrative transfer methodologies presented above were designed for future use. However, the administrative transfer rates on which the methodologies are based should

updated on a periodic basis. Furthermore, as consumer needs change, the operations and staffing levels of HECO may change. Thus, the methodologies and the assumptions developed and made herein should be re-evaluated on an on-going basis.

EXHIBITS AND APPENDICES

Exhibit I

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

GENERAL ACCOUNTING DEPARTMENT

Responsibility Area	Position
Administrative	Controller Executive Secretary, Administrative Staff Accounting Analyst
Corporate Accounting	Director, Corporate Accounting Corporate Accountant (5 positions) Accounting & Statistical Aide
Cost Accounting	Director, Cost Accounting Deduction & Allowance Clerk Accounts Payable & Disbursement Clerk Job Accounting Clerk Accounting Clerk II (2 positions) Accounting Clerk III (2 positions) Accounts Receivable Clerk Payroll Accountant Disbursement Accountant Job Accountant
Taxes & Property Accounting	Director, Taxes & Property Accounting Plant Accounting Clerk Stenographer Clerk Tax Accountant (5 positions) Property Accountant (2 positions) Associate Plant Accountant

Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

ENGINEERING & PROJECT MANAGEMENT DEPARTMENT

Responsibility Area	Position
Administrative	Administrator Manager, Engineering & Project Management Secretary
Land & Rights of Way	Director, Land & Rights of Way Land Agent (4 positions) Land Assistant
Survey	Land Surveyor Transit Technician Survey Rod Helper

CUSTOMER SERVICE DEPARTMENT

Responsibility Area	Position
Customer Assistance Center	Supervisor, Customer Assistance Center Lead Customer Assistance Representative (2 positions) Customer Assistance Representative (26 positions)
Payment Processing & Support Center	Telephone Operator/Receptionist

INFORMATION SERVICES DEPARTMENT

Responsibility Area	Position
Administrative	Manager, Information Services Secretary Principal, Information Services Infrastructure & Planning Principal, Information Services Consulting Information Services Consultant (3 positions)
Computer and Office Services	Director, Computer and Office Services Desktop Coordinators (2 positions) Help Desk Specialist
Systems and Services Development	Director, Systems and Services Development

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Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

INFORMATION SERVICES DEPARTMENT, cont'd.

Responsibility Area	Position

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Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

ENVIRONMENTAL DEPARTMENT

Responsibility Area	Position
Administrative	Manager, Environmental Secretary Clerk Typist III Budget/Statistical Analyst
Air Quality & Emissions	Environmental Specialist (2 positions) Environmental Scientist (4 positions)
Analytical Services	Laboratory Supervisor Senior Analytical Chemist

Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

FINANCIAL SERVICES DEPARTMENT, cont'd.

Responsibility Area	Position
Treasury	Treasury Administrator Senior Treasury Specialist Treasury Specialist

INDUSTRIAL RELATIONS DEPARTMENT

Responsibility Area	Position
Administrative	Manager, Industrial Relations Secretary
Labor Relations & Wage Administration	Director, Labor Relations & Wage Admin. Labor Relations Administrator (3 positions) Industrial Relations Generalist
Workers' Compensation & Personnel Administration	Personnel Assistant

POWER SUPPLY SERVICES DEPARTMENT

Responsibility Area	Position
Administrative	Manager, Power Supply Services
Technical Services	Staff Engineer, Technical Services
Fuels	Director, Fuel Resources Fuels Operations Administrator Fuels Forecaster Fuels Procurement Specialist
Power Purchase	Director, Power Purchase

Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

SUPPORT SERVICES DEPARTMENT

Responsibility Area	Position
Administrative	Manager, Support Services Systems Administrator Secretary
Facilities Maintenance	Working Foreman Senior Electrician (4 positions) Senior Painter Senior Carpenter Certified Welder
Purchasing	Director, Purchasing Senior Clerk Purchasing Clerk (3 positions) Buyer (5 positions)

PLANNING & ENGINEERING DEPARTMENT

Responsibility Area	Position
Administrative	Manager, Planning & Engineering Administrator Secretary
Generation Planning	Director, Generation Planning Lead Engineer Senior Planning Engineer (3 positions) Planning Engineer (4 positions)
Clerical	Project Clerk Clerk Typist III
Power Plant Project Management	Project Manager
Power Plant Mechanical Engineering	Project Manager Principal Engineer
Integrated Resource Planning	Director, Integrated Resource Planning Energy Specialist Planning Engineer (2 positions)

Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

SENIOR MANAGEMENT

Responsibility Area	Position
VP-Energy Delivery	VP-Energy Delivery Executive Secretary
VP-Regulatory Affairs	VP-Regulatory Affairs Executive Secretary Executive Staff Assistant
Financial VP/Treasurer's Office	Financial VP & Treasurer Executive Secretary
VP- General Counsel & Government Relations' Office	VP-General Counsel & Government Relations Executive Secretary
VP-Corporate Excellence's Office	VP-Corporate Excellence Executive Secretary HR System Analyst Consultant, HR Information System
VP-Power Supply	VP-Power Supply Executive Secretary
VP-Customer Operations	VP-Customer Operations Executive Secretary Executive Staff Engineer
President's Office	President & CEO, HECO Director, Strategic Initiatives Administrator Corporate Secretary

OTHER ORGANIZATIONS

Responsibility Area	Position
Management Accounting	Director, Management Accounting Clerk Typist III Management Accounting Technical Coordinator Management Accounting Analyst (4 positions) Accounting Systems Analyst (3 positions)
Compensation	Director, Compensation Compensation Analyst (2 positions) Compensation Coordinator

Exhibit I - cont'd.

LISTING OF POSITIONS CHARGING THE 920.00 ACCOUNT

OTHER ORGANIZATIONS, cont.'d

Responsibility Area	Position
Employment & Human Resource Development	Coordinator Consultant (2 positions) Workforce Diversity & Planning Analyst
Organizational Development & Continuous Improvement	Manager, Organizational Development & Continuous Improvement Continuous Improvement Consultant (4 positions) Junior Control Operator Department Temporary
Internal Audit	Director, Internal Audit Internal Auditor (3 positions)
Legal	Manager, Legal Associate General Counsel (5 positions) Legal Assistant (2 positions) Legal Secretary (3 positions)
Government Relations	Director, Government Relations Administrative Assistant
Regulatory Affairs	Director, Regulatory Affairs

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Exhibit II

LISTING OF POSITIONS IDENTIFIED FOR TIME STUDY PARTICIPATION

Position	Construction Task	Basis for Inclusion in Time Study
Accounting	Accounts	Incremental cost principle (i.e., if there were no construction, the Cost

Exhibit II - cont'd.

LISTING OF POSITIONS IDENTIFIED FOR TIME STUDY PARTICIPATION

Position	Construction Task	Basis for Inclusion in Time Study
Land Agent (4 positions)	Research and/or land acquisition	Incremental cost principle (i.e., if there were no construction, the Land & Rights of Way staff would probably be reduced) and certain tasks performed by this position have an initial, direct and definite relation to construction.
Land Assistant	Research and/or land acquisition	Same as the Land Agents explanation above.
Plant Accounting Clerk	Job Costing	Same as Associate Plant Accountant explanation above.
Property Accountant	Job Costing	Same as Associate Plant Accountant explanation above.
Purchasing Clerk (3 positions)	Purchasing	Same as the Buyers explanation above.
Senior Clerk	Purchasing	Same as the Buyers explanation above.

Exhibit III

POSITIONS NOT SUBJECT TO TIME STUDY

Interviews were conducted with representatives from the responsibility areas listed below to obtain an understanding of the activities performed by the following responsibility area positions. In addition, job descriptions for the responsibility area positions listed below were reviewed to validate the results of our interviews. Based upon our understanding of the activities performed by these employees and the construction related activity definition established in Phase I of this project (Refer to Section 4, Development of Methodology to Determine Administrative Costs to Transfer to Construction), it was concluded that the following employees do not satisfy the incremental cost principle and/or time spent by these employees on construction activities are either directly charged to the construction project or to a clearing account other than the 920.00 account. Accordingly, these employees were excluded from the time study.

GENERAL ACCOUNTING DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Controller	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
Staff Accounting Analyst	Does not meet the incremental cost principle.
Corporate Accounting	
Director, Corporate Accounting	Does not meet the incremental cost principle.
Corporate Accountant (5 positions)	Does not meet the incremental cost principle.
Accounting & Statistical Aide	Does not meet the incremental cost principle.
Cost Accounting	
Director, Cost Accounting	Does not meet the incremental cost principle.
Deduction & Allowance Clerk	Does not meet the incremental cost principle.
Accounts Receivable Clerk	Does not meet the incremental cost principle.
Payroll Accountant	Does not meet the incremental cost principle.
Disbursement Accountant	Does not meet the incremental cost principle.
Taxes & Property Accounting	
Director, Taxes & Property Accounting	Does not meet the incremental cost principle.
Stenographer Clerk	Does not meet the incremental cost principle.
Tax Accountant (5 positions)	Does not meet the incremental cost principle.
Property Accountant	Does not meet the incremental cost principle.

Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

ENGINEERING & PROJECT MANAGEMENT DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Administrator	Does not meet the incremental cost principle.
Manager, Engineering & Project Management	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Land & Rights of Way	
Director, Land & Rights of Way	Does not meet the incremental cost principle.
Survey	
Land Surveyor	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project or to a clearing account.
Transit Technician	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project or to a clearing account.
Survey Rod Helper	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project or to a clearing account.

CUSTOMER SERVICE DEPARTMENT

Position	Basis for Exclusion from Time Study
Customer Assistance Center	
Supervisor, Customer Assistance Center	Does not meet the incremental cost principle.
Lead Customer Assistance Representative (2 positions)	Does not meet the incremental cost principle.
Customer Assistance Representative (26 positions)	Does not meet the incremental cost principle.
Payment Processing & Support Center	
Telephone Operator/Receptionist	Does not meet the incremental cost principle.

Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

INFORMATION SERVICES DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Manager, Information Services	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Principal, Information Services Infrastructure & Planning	Does not meet the incremental cost principle.
Principal, Information Services Consulting	Does not meet the incremental cost principle.
Information Services Consultant (3 positions)	Meets the construction activity definition. However, time spent on construction activities is charged to clearing account(s).
Computer and Office Services	
Director, Computer and Office Services	Does not meet the incremental cost principle.
Desktop Coordinator (2 positions)	Does not meet the incremental cost principle.
Help Desk Specialist	Does not meet the incremental cost principle.
Systems and Services Development	
Director, Systems and Services Development	Does not meet the incremental cost principle.
Mailing	
Supervisor, Mailing Services	Does not meet the incremental cost principle.
Mail Clerk I (7 positions)	Does not meet the incremental cost principle.
Mail Clerk II	Does not meet the incremental cost principle.
Materials & Stationery Aide	Does not meet the incremental cost principle.
Publishing & Records Services	
Supervisor, Publishing & Records Services	Does not meet the incremental cost principle.
Senior Press Operator	Does not meet the incremental cost principle.
Printer III (2 positions)	Does not meet the incremental cost principle.
Information Store Equipment Operator	Does not meet the incremental cost principle.
Senior Word Processing Operator (2 positions)	Does not meet the incremental cost principle.
Publishing Services Coordinator	Does not meet the incremental cost principle.
Records Management Coordinator	Does not meet the incremental cost principle.
Network Services	
Network Analyst	Does not meet the incremental cost principle.
Network Specialist	Does not meet the incremental cost principle.

Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

ENERGY SERVICES DEPARTMENT

Position	Basis for Exclusion from Time Study
Forecasts	
Director, Forecasts	Does not meet the incremental cost principle.
Planning Analyst (4 positions)	Does not meet the incremental cost principle.
Research and Evaluation	
Planning Analyst	Does not meet the incremental cost principle.
Analyst	Does not meet the incremental cost principle.
Pricing	
Director, Pricing	Does not meet the incremental cost principle.
Analyst (2 positions)	Does not meet the incremental cost principle.

FACILITIES DEPARTMENT

Position	Basis for Exclusion from Time Study
Buildings & Grounds	
Supervisor, Buildings & Grounds	Does not meet the incremental cost principle.
Custodian IV (2 positions)	Does not meet the incremental cost principle.
Custodian II (2 positions)	Does not meet the incremental cost principle.
Custodian (8 positions)	Does not meet the incremental cost principle.
Facilities Planning	
Facilities Planning Clerk	Does not meet the incremental cost principle.
Security	
Security Coordinator	Does not meet the incremental cost principle.
Security Officer (10 positions)	Does not meet the incremental cost principle.

ENVIRONMENTAL DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Manager, Environmental	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Clerk Typist III	Does not meet the incremental cost principle.
Budget/Statistical Analyst	Does not meet the incremental cost principle.

Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

ENVIRONMENTAL DEPARTMENT, cont'd.

Position	Basis for Exclusion from Time Study
Air Quality & Emissions	
Environmental Specialist (2 positions)	Does not meet the incremental cost principle.
Environmental Scientist (3 positions)	Does not meet the incremental cost principle.
Environmental Scientist	Meets the construction activity definition. However, time spent on construction activities is charged directly to the construction project.
Analytical Services	
Laboratory Supervisor	Does not meet the incremental cost principle.
Senior Analytical Chemist	Does not meet the incremental cost principle.
Analytical Chemist (4 positions)	Does not meet the incremental cost principle.
Water and Hazardous Materials	
Graphics Specialist	Does not meet the incremental cost principle.
Principal Environment Scientist	Does not meet the incremental cost principle.
Environmental Scientist (3 positions)	Does not meet the incremental cost principle.

FINANCIAL SERVICES DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Assistant Treasurer & Manager	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Financial Services Consultant	Does not meet the incremental cost principle.
Capital Budgets	
Capital Budgets Administrator	Does not meet the incremental cost principle.
Capital Budgets System Analyst	Meets the construction activity definition. However, time spent on construction activities is charged to a clearing account.
Capital Budgets Analyst	Meets the construction activity definition. However, time spent on construction activities is charged to a clearing account.
Scheduler Technician	Meets the construction activity definition. However, time spent on construction activities is charged to a clearing account.

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Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

FINANCIAL SERVICES DEPARTMENT, cont'd.

Position	Basis for Exclusion from Time Study
Financial Analysis	
Senior Financial Analyst	Does not meet the incremental cost principle.
Financial Analyst	Does not meet the incremental cost principle.
Risk Management	
Director, Risk Management	Does not meet the incremental cost principle.
Clerk Stenographer	Does not meet the incremental cost principle.
Claims Representative	Does not meet the incremental cost principle.
Claims Administrator	Does not meet the incremental cost principle.
Claims Adjuster (2 positions)	Does not meet the incremental cost principle.
Insurance Administrator	Does not meet the incremental cost principle.
Insurance Coordinator	Does not meet the incremental cost principle.
Securities	
Securities Administrator	Does not meet the incremental cost principle.
Securities Specialist	Does not meet the incremental cost principle.
Treasury	
Treasury Administrator	Does not meet the incremental cost principle.
Senior Treasury Specialist	Does not meet the incremental cost principle.
Treasury Specialist	Does not meet the incremental cost principle.

INDUSTRIAL RELATIONS DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Manager, Industrial Relations	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Labor Relations & Wage Administration	
Director, Labor Relations & Wage Administration	Does not meet the incremental cost principle.

Exhibit III- cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

POWER SUPPLY SERVICES DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Manager, Power Supply Services	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Technical Services	
Staff Engineer, Technical Services	Does not meet the incremental cost principle.
Fuels	
Director, Fuel Resources	Does not meet the incremental cost principle.
Fuels Operations Administrator	Does not meet the incremental cost principle.
Fuels Forecaster	Does not meet the incremental cost principle.
Fuels Procurement Specialist	Does not meet the incremental cost principle.
Power Purchase	
Director, Power Purchase	Does not meet the incremental cost principle.

SUPPORT SERVICES DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Manager, Support Services	Does not meet the incremental cost principle.
Systems Administrator	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Facilities Management	
Working Foreman	Does not meet the incremental cost principle.
Senior Electrician (4 positions)	Does not meet the incremental cost principle.
Senior Painter	Does not meet the incremental cost principle.
Senior Carpenter	Does not meet the incremental cost principle.
Certified Welder	Does not meet the incremental cost principle.
Purchasing	
Director, Purchasing	Does not meet the incremental cost principle.
Buyer	Does not meet the incremental cost principle.

POSITIONS NOT SUBJECT TO TIME STUDY

PLANNING & ENGINEERING DEPARTMENT

Position	Basis for Exclusion from Time Study
Administrative	
Manager, Planning & Engineering	Does not meet the incremental cost principle.
Administrator	Does not meet the incremental cost principle.
Secretary	Does not meet the incremental cost principle.
Generation Planning	
Director, Generation Planning	Does not meet the incremental cost principle.
Lead Engineer	
Senior Planning Engineer (2 positions)	Does not meet the incremental cost principle.
Senior Planning Engineer	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project, a billable account, or a clearing account.
Planning Engineer (4 positions)	Does not meet the incremental cost principle.
Clerical	
Project Clerk	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project, a billable account, or a clearing account.
Clerk Typist III	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project, a billable account, or a clearing account.
Power Plant Project Management	
Project Manager	Meets the construction activity definition. However, time spent on construction activities is charged either directly to the construction project, a billable account, or a clearing account.
Power Plant Mechanical Engineering	
Project Manager	Does not meet the incremental cost principle.
Principal Engineer	Meets the construction activity definition. However, time spent on construction activities is charged directly to the construction project.

Exhibit III- cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

PLANNING & ENGINEERING DEPARTMENT, cont'd.

Position	Basis for Exclusion from Time Study
Integrated Resource Planning	
Director, Integrated Resource Planning	Does not meet the incremental cost principle.
Energy Specialist	Does not meet the incremental cost principle.
Planning Engineer (2 positions)	Does not meet the incremental cost principle.

SENIOR MANAGEMENT

Position	Basis for Exclusion from Time Study
VP-Energy Delivery	
VP-Energy Delivery	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
VP-Regulatory Affairs	
VP-Regulatory Affairs	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
Executive Staff Assistant	Does not meet the incremental cost principle.
Financial VP/Treasurer's Office	
Financial VP & Treasurer	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
VP-General Counsel & Government Relations' Office	
VP-General Counsel & Government Relations	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
VP-Corporate Excellence's Office	
VP-Corporate Excellence	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
HR System Analyst	Does not meet the incremental cost principle.
Consultant, HR Information System	Does not meet the incremental cost principle.
VP-Power Supply	
VP-Power Supply	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.
VP-Customer Operations	
VP-Customer Operations	Does not meet the incremental cost principle.
Executive Secretary	Does not meet the incremental cost principle.

Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

SENIOR MANAGEMENT, cont'd.

Position	Basis for Exclusion from Time Study
Executive Staff Engineer	Does not meet the incremental cost principle.
President's Office	
President & CEO, HECO	Does not meet the incremental cost principle.
Director, Strategic Initiatives	Does not meet the incremental cost principle.
Administrator	Does not meet the incremental cost principle.
Corporate Secretary	Does not meet the incremental cost principle.

OTHER ORGANIZATIONS

Position	Basis for Exclusion from Time Study
Management Accounting	
Director, Management Accounting	Does not meet the incremental cost principle.
Clerk Typist III	Does not meet the incremental cost principle.
Management Accounting Technical Coordinator	Does not meet the incremental cost principle.
Management Accounting Analyst (4 positions)	Does not meet the incremental cost principle.
Accounting System Analyst (3 positions)	Does not meet the incremental cost principle.
Compensation	
Director, Compensation	Does not meet the incremental cost principle.
Compensation Analyst (2 positions)	Does not meet the incremental cost principle.
Compensation Coordinator	Does not meet the incremental cost principle.
Employment & Human Resource Development	
Workforce Diversity & Planning Analyst	Does not meet the incremental cost principle.
Organizational Development & Continuous Improvement	
Manager, Organizational Development & Continuous Improvement	Does not meet the incremental cost principle.
Continuous Improvement Consultant (4 positions)	Does not meet the incremental cost principle.
Junior Control Operator	Does not meet the incremental cost principle.
Department Temporary	Does not meet the incremental cost principle.

Exhibit III - cont'd.

POSITIONS NOT SUBJECT TO TIME STUDY

OTHER ORGANIZATIONS, cont'd.

Position	Basis for Exclusion from Time Study
Internal Audit	
Director, Internal Audit	Does not meet the incremental cost principle.
Internal Auditor (3 positions)	Does not meet the incremental cost principle.
Legal	
Manager, Legal	Does not meet the incremental cost principle.
Associate General Counsel (5 positions)	Does not meet the incremental cost principle.
Legal Assistant (2 positions)	Does not meet the incremental cost principle.
Legal Secretary (3 positions)	Does not meet the incremental cost principle.
Government Relations	
Director, Government Relations	Does not meet the incremental cost principle.
Administrative Assistant	Does not meet the incremental cost principle.
Regulatory Affairs	
Director, Regulatory Affairs	Does not meet the incremental cost principle.
Regulatory Analyst (4 positions)	Does not meet the incremental cost principle.
Rate Clerk	Does not meet the incremental cost principle.
Administrative Assistant	Does not meet the incremental cost principle.
Telecommunications	
Director, Telecommunications	Does not meet the incremental cost principle.
Senior Telecommunications Consultant	Does not meet the incremental cost principle.
Engineer II	Meets the construction activity definition. However, any time spent on construction activities is charged directly to the construction project.
Corporate Communications	
Director, Corporate Communications	Does not meet the incremental cost principle.
Communications Consultant/Editor (2 positions)	Does not meet the incremental cost principle.
Communications Consultant (3 positions)	Does not meet the incremental cost principle.
Visual Communications Consultant (3 positions)	Does not meet the incremental cost principle.
Clerk Typist III	Does not meet the incremental cost principle.

Exhibit IV

COST POOL/DRIVER REPORT
For the One Month Period Ended June 30, 1996

Cost Pool Code	Cost Pool Description	Driver Code	Driver Description	Cost Category	Cost Pool Total
AC21S	Accounting Clerk II Salary-Position 1	AC21H	Accounting Clerk II Hours-Position 1	Personnel Costs (PC)	1,903
AC22S	Accounting Clerk II Salary-Position 2	AC22H	Accounting Clerk II Hours-Position 2	PC	1,898
AC31S	Accounting Clerk III Salary-Position 1	AC31H	Accounting Clerk III Hours-Position 1	PC	2,053
AC32S	Accounting Clerk III Salary-Position 2	AC32H	Accounting Clerk III Hours-Position 2	PC	2,970
APAS	Associate Plant Accountant Salary	APAH	Associate Plant Accountant Hours	PC	3,277
APDCS	A/P & Disbursement Clerk Salary	APDCH	A/P & Disbursement Clerk Hours	PC	3,315
BS1	Buyer Salary-Position 1	BH1	Buyer Hours-Position 1	PC	4,139
BS2	Buyer Salary-Position 2	BH2	Buyer Hours-Position 2	PC	2,992
BS3	Buyer Salary-Position 3	BH3	Buyer Hours-Position 3	PC	3,754
BS4	Buyer Salary-Position 4	BH4	Buyer Hours-Position 4	PC	3,116
ECS1	Employment & Human Resource Development Consultant Salary-Position 1	ECH1	Employment & Human Resource Development Consultant Hours-Position 1	PC	3,923
ECS2	Employment & Human Resource Development Consultant Salary-Position 2	ECH2	Employment & Human Resource Development Consultant Hours-Position 2	PC	4,300
HRCS	Employment & Human Resource Coordinator Salary	HRCH	Employment & Human Resource Development Coordinator Hours	PC	2,600
JACS	Job Accounting Clerk Salary	JACH	Job Accounting Clerk Hours	PC	3,726
JAS	Job Accountant Salary	JAH	Job Accountant Hours	PC	3,892
LAS1	Land Agent Salary-Position 1	LAH1	Land Agent Hours-Position 1	PC	4,600
LAS2	Land Agent Salary-Position 2	LAH2	Land Agent Hours-Position 2	PC	4,469
LAS3	Land Agent Salary-Position 3	LAH3	Land Agent Hours-Position 3	PC	4,223
LAS4	Land Agent Salary-Position 4	LAH4	Land Agent Hours-Position 4	PC	4,192
LASS	Land Assistant Salary	LASH	Land Assistant Hours	PC	2,681
PACS	Plant Accounting Clerk Salary	PACH	Plant Accounting Clerk Hours	PC	3,315
PAS	Property Accountant Salary	PAH	Property Accountant Hours	PC	3,938
PCS1	Purchasing Clerk Salary-Position 1	PCH1	Purchasing Clerk Hours-Position 1	PC	2,882
PCS2	Purchasing Clerk Salary-Position 2	PCH2	Purchasing Clerk Hours-Position 2	PC	2,882
PCS3	Purchasing Clerk Salary-Position 3	PCH3	Purchasing Clerk Hours-Position 3	PC	2,613
SCS	Senior Clerk Salary	SCH	Senior Clerk Hours	PC	3,531
	Total Costs for Allocation				87,184

Exhibit IV - cont'd.

COST POOL/DRIVER REPORT

For the One Month Period Ended July 31, 1996

Cost Pool Code	Cost Pool Description	Driver Code	Driver Description	Cost Category	Cost Pool Total
AC21S	Accounting Clerk II Salary-Position 1	AC21H	Accounting Clerk II Hours-Position 1	Personnel Costs (PC)	2,252
AC22S	Accounting Clerk II Salary-Position 2	AC22H	Accounting Clerk II Hours-Position 2	PC	2,154
AC31S	Accounting Clerk III Salary-Position 1	AC31H	Accounting Clerk III Hours-Position 1	PC	2,361
AC32S	Accounting Clerk III Salary-Position 2	AC32H	Accounting Clerk III Hours-Position 2	PC	3,460
APAS	Associate Plant Accountant Salary	APAH	Associate Plant Accountant Hours	PC	3,769
APDCS	A/P & Disbursement Clerk Salary	APDCH	A/P & Disbursement Clerk Hours	PC	3,812
BS1	Buyer Salary-Position 1	BH1	Buyer Hours-Position 1	PC	4,759
BS2	Buyer Salary-Position 2	BH2	Buyer Hours-Position 2	PC	3,441
BS3	Buyer Salary-Position 3	BH3	Buyer Hours-Position 3	PC	4,317
BS4	Buyer Salary-Position 4	BH4	Buyer Hours-Position 4	PC	3,583
ECS1	Employment & Human Resource Development Consultant Salary-Position 1	ECH1	Employment & Human Resource Development Consultant Hours-Position 1	PC	4,511
ECS2	Employment & Human Resource Development Consultant Salary-Position 2	ECH2	Employment & Human Resource Development Consultant Hours-Position 2	PC	4,945
HRCS	Employment & Human Resource Development Coordinator Salary	HRCH	Employment & Human Resource Development Coordinator Hours	PC	2,990
JACS	Job Accounting Clerk Salary	JACH	Job Accounting Clerk Hours	PC	4,285
JAS	Job Accountant Salary	JAH	Job Accountant Hours	PC	4,476
LAS1	Land Agent Salary-Position 1	LAH1	Land Agent Hours-Position 1	PC	5,290
LAS2	Land Agent Salary-Position 2	LAH2	Land Agent Hours-Position 2	PC	5,140
LAS3	Land Agent Salary-Position 3	LAH3	Land Agent Hours-Position 3	PC	4,857
LAS4	Land Agent Salary-Position 4	LAH4	Land Agent Hours-Position 4	PC	4,821
LASS	Land Assistant Salary	LASH	Land Assistant Hours	PC	2,706
PACS	Plant Accounting Clerk Salary	PACH	Plant Accounting Clerk Hours	PC	3,813
PAS	Property Accountant Salary	PAH	Property Accountant Hours	PC	4,529
PCS1	Purchasing Clerk Salary-Position 1	PCH1	Purchasing Clerk Hours-Position 1	PC	3,328
PCS2	Purchasing Clerk Salary-Position 2	PCH2	Purchasing Clerk Hours-Position 2	PC	3,314
PCS3	Purchasing Clerk Salary-Position 3	PCH3	Purchasing Clerk Hours-Position 3	PC	3,005
SCS	Senior Clerk Salary	SCH	Senior Clerk Hours	PC	4,061
	Total Costs for Allocation				99,979

Exhibit IV - cont'd.

RECONCILIATION OF GENERAL LEDGER TO COSTS FOR ALLOCATION REPORT

For the One Month Period Ended June 30, 1996

Total Costs per General Ledger	$ 1,038,515
Deduct Excluded Costs (Non-Time Study Salaries) From General Ledger Entry:	< 951,331 >
Total Costs for Allocation	$ 87,184

Exhibit IV - cont'd.

RECONCILIATION OF GENERAL LEDGER TO COSTS FOR ALLOCATION REPORT

For the One Month Period Ended July 31, 1996

Total Costs per General Ledger	$ 1,156,655
Deduct Excluded Costs (Non-Time Study Salaries) From General Ledger Entry:	< 1,056,676 >
Total Costs for Allocation	$ 99,979

Exhibit V

VARIANCES FROM THE USE OF DIRECT HOURS AS COST DRIVERS

Based upon our discussions with the time study participants and an evaluation of the nature of the following participants' tasks, we concluded that it would not only be time consuming (e.g., due to the volume of invoices being processed) for these individuals to monitor the amount of time that they spend on certain construction related and non-construction related tasks but that this may also distort the allocation amounts (e.g., where should the additional time spent on separating the invoices be recorded). Thus, based upon our discussions with the time study participants and the respective responsibility area supervisors, it was concluded that the best way to allocate these individuals' time is as follows:

Accounting Clerk II (2 positions)
The Accounting Clerk IIs recorded their time by summarizing their daily tasks and identifying construction related activities by line item on their time sheets. According to the Accounting Clerk IIs, time spent on the processing of invoices may be either construction or non-construction related. As such, time spent on processing invoices was allocated to construction based on the ratio of the number of construction invoices processed to the total number of invoices processed.

Accounting Clerk III (2 positions)
The Accounting Clerk IIIs recorded their time by summarizing their daily tasks and identifying construction related activities by line item on their time sheets. According to the Accounting Clerk IIIs, time spent on the processing of invoices may be either construction or non-construction related. As such, time spent on the processing of invoices was allocated to construction based on the ratio of the number of construction invoices processed to the total number of invoices processed.

Associate Plant Accountant
The Associate Plant Accountant recorded her time by summarizing her daily tasks and identifying construction related activities by line item on her time sheet. According to the Associate Plant Accountant, time spent on updating the master file may be either construction (plant installs) or non-construction (plant retirements) related. Thus, the Associate Plant Accountant's time spent on updating the master file was allocated to construction based on the ratio of plant installs to the sum of the plant installs plus plant retirements.

Exhibit V - cont'd.

VARIANCES FROM THE USE OF DIRECT HOURS AS COST DRIVERS

Accounts Payable and Disbursement Clerk
The Accounts Payable and Disbursement Clerk recorded her time by summarizing her daily tasks and identifying construction related activities by line item on her time sheet. According to the Disbursement Accountant, time spent on the processing of invoices may be either construction or non-construction related. As such, time spent on the processing of invoices was allocated to construction based on the ratio of the number of construction invoices processed to the total number of invoices processed.

Buyer (4 positions)
The Buyers recorded their time by identifying time spent on processing and following up on purchase orders; estimating the retention payable amount for construction related purchase orders; matching invoices with the respective purchase orders and following up on any discrepancies; and other miscellaneous activities (e.g., answering phones, meetings, classes, etc.). According to the Buyers, the only difference in processing time between a construction related purchase order and a non-construction purchase order is the time spent on the estimation of the retention payable amount. As such, all the Buyers' time spent on retention payables was considered construction related. The Buyer's time spent on the processing of purchase orders was allocated to construction based on a ratio of the number of construction purchase orders processed to the total number of purchase orders processed. The Buyers' time spent on the matching of invoices with the respective purchase orders was allocated to construction based on the purchase order counts.

The Buyer - Positions 1 and 2's tasks also included the processing of Production Stores purchase orders. As the Production Stores purchase orders are charged to the Production Stores clearing account (account number 164.00), the Buyers' time spent on the processing of the Production Stores purchase orders was allocated to construction and non-construction based on the monthly clearing rates of the Production Stores clearing account.

The Buyer - Position 3's tasks also included the processing of Production Stores and Transmission & Distribution (T&D) Stores purchase orders. As the Production Stores and T&D Stores purchase orders are charged to the respective Production stores

Exhibit V - cont'd.

VARIANCES FROM THE USE OF DIRECT HOURS AS COST DRIVERS

Buyer (4 positions), cont'd.
clearing account (account number 164.00) and T&D Stores clearing account (account number 163.00), the Buyer - Position 3's time spent on the processing of Production Stores and T&D Stores purchase orders was allocated to construction and non-construction based on the monthly clearing rates of the Production Stores and T&D Stores clearing accounts.

The Buyer - Position 4's tasks also included the processing of T&D Stores and Tool Room purchase orders. As the T&D Stores and Tool Room purchase orders are charged to the T&D Stores clearing account (account number 163.00) and the Tool Room clearing account (account number 184.20), the Buyer - Position 4's time spent on the ordering of T&D Stores and Tool Room items was allocated to construction and non-construction based on the applicable clearing rates of the T&D Stores and Tool Room clearing accounts.

According to the Buyer- Position 4, time spent on Systems Operations and Standards Division ordering can be either construction or non-construction. As such, the Buyer - Position 4's time spent on Systems Operations and Standards Division ordering was allocated to construction based on the ratio of the number of construction purchase orders processed to the total number of purchase orders processed.

Employment & Human Resource Development Consultant (2 positions)
The Employment & Human Resource Development Consultants recorded their time by segregating their daily tasks between construction and non-construction related activities by line item on their time sheets. The Employment & Human Resource Development Consultants also recorded their time by activity numbers to facilitate the determination of the amount of time being charged to the 920.00 account. According to the Employment & Human Resource Development Consultants, construction related tasks are identified with a check mark next to the respective item on the time sheets. The Employment & Human Resource Development Consultants allocated their time spent on the hiring (staffing) and recruiting of employees to construction and non-construction based on a ratio of the number of construction related employees hired and/or recruited to the total number of employees hired and/or recruited.

Exhibit V - cont'd.

VARIANCES FROM THE USE OF DIRECT HOURS AS COST DRIVERS

Employment & Human Resource Development Coordinator
The Employment & Human Resource Development Coordinator recorded his time similarly to the Employment & Human Resource Development Consultants described above.

Plant Accounting Clerk
The Plant Accounting Clerk recorded her time similarly to the Associate Plant Accountant described above.

Property Accountant
The Property Accountant recorded her time similarly to the Associate Plant Accountant described above.

Purchasing Clerk (3 positions)
The Purchasing Clerks recorded their time by identifying time spent on processing and following up on purchase orders; matching invoices with the respective purchase orders and following up on any discrepancies; and other miscellaneous activities (e.g., answering phones, meetings, classes, etc.). The Purchasing Clerks' time spent on the processing of purchase orders was allocated to construction based on a ratio of the number of construction purchase orders processed to the total number of purchase orders processed. The Purchasing Clerks' time spent on the matching of invoices with the respective purchase orders was allocated to construction based on the purchase order counts.

The Purchasing Clerk - Position 2's tasks also included the processing of T& D Stores purchase orders and other purchase orders. According to the Purchasing Clerk - Position 2, construction related tasks related to the processing of T&D Stores purchase orders are denoted with a checkmark on the timesheet.

The Purchasing Clerk - Position 3's tasks also included the processing of Production Stores purchase orders and other purchase orders. According to the Purchasing Clerk - Position 3, construction related tasks related to the processing of Production Stores purchase orders are denoted with a checkmark on the timesheet.

Exhibit V - cont'd.

VARIANCES FROM THE USE OF DIRECT HOURS AS COST DRIVERS

Senior Clerk

The Senior Clerk recorded her time by identifying time spent on processing and following up on purchase orders; matching invoices with the respective purchase orders and following up on any discrepancies; and other miscellaneous activities (e.g., [illegible] phones, meetings, classes, etc.). The Senior Clerk's time spent on

[redacted]

processing purchase orders was allocated to construction based on a ratio of the number of construction purchase orders processed to the total number of purchase orders processed. The Senior Clerk's time spent on the matching of invoices with the respective purchase orders was allocated to construction based on the purchase order counts.

The Senior Clerk's tasks also included the processing of T&D Stores freight. As the T&D Stores freight is charged to the T&D Stores clearing account (account number 163.00), the Senior Clerk's time spent on the processing of the T&D Stores freight was allocated to construction and non-construction based on the monthly clearing rates of the T&D Stores clearing account.

Exhibit VI

TOTAL COST ALLOCATION REPORT
For the One Month Period Ended June 30, 1996

Cost Categories/Cost Pools	Cost Pool Total	Construction	Non-construction
Accounting Clerk II Salary-Position 1	1,903	456	1,447
Accounting Clerk II Salary-Position 2	1,898	516	1,382
Accounting Clerk III Salary-Position 1	2,053	620	1,433
Accounting Clerk III Salary-Position 2	2,970	844	2,126
Associate Plant Accountant Salary	3,277	3,177	100
A/P & Disbursement Clerk Salary	3,315	910	2,405
Buyer Salary-Position 1	4,139	800	3,339
Buyer Salary-Position 2	2,992	798	2,194
Buyer Salary-Position 3	3,754	3,652	102
Buyer Salary-Position 4	3,116	1,748	1,368
Employment & Human Resource Development Consultant Salary-Position 1	3,923	0	3,923
Employment & Human Resource Development Consultant Salary-Position 2	4,300	0	4,300
Employment & Human Resource Development Coordinator Salary	2,600	0	2,600
Job Accounting Clerk Salary	3,726	3,481	245
Job Accountant Salary	3,892	1,872	2,020
Land Agent Salary-Position 1	4,600	2,664	1,936
Land Agent Salary-Position 2	4,469	2,742	1,727
Land Agent Salary-Position 3	4,223	1,675	2,548
Land Agent Salary-Position 4	4.192	923	3,269
Land Assistant Salary	2,681	983	1,698
Plant Accounting Clerk Salary	3,315	0	3,315
Property Accountant Salary	3,938	3,938	0
Purchasing Clerk Salary-Position 1	2,882	535	2,347
Purchasing Clerk Salary-Position 2	2,882	1,420	1,462
Purchasing Clerk Salary-Position 3	2,613	127	2,486
Senior Clerk Salary	3,531	2,040	1,491
PERSONNEL COSTS TOTAL	$87,184	$35,921	$51,263

Hawaiian Electric Company, Inc.
Administrative Transfer Study

Exhibit VI - cont'd.

TOTAL COST ALLOCATION REPORT
For the One Month Period Ended July 31, 1996

Cost Categories/Cost Pools	Cost Pool Total	Construction	Non-construction
Accounting Clerk II Salary-Position 1	2,252	381	1,871
Accounting Clerk II Salary-Position 2	2,154	555	1,599
Accounting Clerk III Salary-Position 1	2,361	700	1,661
Accounting Clerk III Salary-Position 2	3,460	913	2,547
Associate Plant Accountant Salary	3,769	3,634	135
A/P & Disbursement Clerk Salary	3,812	951	2,861
Buyer Salary-Position 1	4,759	890	3,869
Buyer Salary-Position 2	3,441	945	2,496
Buyer Salary-Position 3	4,317	3,891	426
Buyer Salary-Position 4	3,583	1,659	1,924
Employment & Human Resource Development Consultant Salary-Position 1	4,511	0	4,511
Employment & Human Resource Development Consultant Salary-Position 2	4,945	0	4,945
Employment & Human Resource Development Coordinator Salary	2,990	0	2,990
Job Accounting Clerk Salary	4,285	4,154	131
Job Accountant Salary	4,476	2,211	2,265
Land Agent Salary-Position 1	5,290	2,849	2,441
Land Agent Salary-Position 2	5,140	2,277	2,863
Land Agent Salary-Position 3	4,857	2,837	2,020
Land Agent Salary-Position 4	4,821	758	4,063
Land Assistant Salary	2,706	573	2,133
Plant Accounting Clerk Salary	3,813	439	3,374
Property Accountant Salary	4,529	792	3,737
Purchasing Clerk Salary-Position 1	3,328	535	2,793
Purchasing Clerk Salary-Position 2	3,314	1,669	1,645
Purchasing Clerk Salary-Position 3	3,005	38	2,967
Senior Clerk Salary	4,061	2,568	1,493
PERSONNEL COSTS TOTAL	$99,979	$36,219	$63,760

Exhibit VII

CALCULATION OF ADMINISTRATIVE TRANSFER RATES

I. 920.00 Administrative and General Salaries Account

The administrative transfer rates for the 920.00 account for the time study and validating time study periods and the formula used to calculate the rates are presented below:

Time Study Period Ended	Transfer rate
June 30, 1996	41%
July 31, 1996	36%

FORMULA:

$$\text{Administrative Transfer Rate} = \frac{\text{Total Construction Related 920.00 Administrative Salaries \& Wages}}{\text{Total Time Study Participant 920.00 Salaries \& Wages}}$$

The total construction related 920.00 administrative salaries and wages for the time study and validating time study periods were calculated by totaling the construction related portion of each time study participant's 920.00 administrative salaries and wages. The construction related portion of each time study participant's 920.00 administrative salaries and wages was determined using the formula below

$$\text{Individual Participant's Construction Related Administrative Salaries \& Wages} = \frac{\text{Individual Participant's Total Construction Related Administrative 920.00 Labor Hours}^{1}}{\text{Individual Participant's Total Labor Hours Worked}^{2}} \times \text{Individual Participant's Salaries \& Wages}^{3}$$

1 Excludes labor hours directly charged to specific construction projects

2 Excludes labor hours directly charged to specific construction projects and nonproductive hours such as holiday, sick, vacation, military leave, jury duty, etc.

3 Reduced for labor costs directly charged to specific construction projects

Exhibit VII - cont'd.

CALCULATION OF ADMINISTRATIVE TRANSFER RATES

I.	920.00 Administrative and General Salaries Account

TIME STUDY RESULTS:

For the one month time study period ended June 30, 1996,

$$41\% = \frac{\$\ 35{,}921}{\$\ 87{,}184}$$

For the one month time study period ended July 31, 1996,

$$36\% = \frac{\$\ 36{,}219}{\$\ 99{,}979}$$

Exhibit VII - cont'd.

CALCULATION OF ADMINISTRATIVE TRANSFER RATES

II. 921.00 Office Supplies and Expense Account

The administrative transfer rates for the 921.00 account for the time study and validating time study periods and the formula used to calculate the rates are presented below:

Time Study Period Ended	Transfer Rate
June 30, 1996	6%
July 31, 1996	5%

FORMULA:

$$\text{Administrative Transfer Rate} = \frac{\text{Total Construction Related Administrative Labor Hours}^{1}}{\text{Total Productive 920.00 Administrative Labor Hours}^{2}}$$

The administrative costs allocable to construction for the 921.00 account for the time study and validating time study period amounted to $28,307 and $25,169, respectively. The formula used to calculate the administrative costs allocable to construction is as follows:

$$\text{Administrative Costs Allocable to Construction} = \text{Total 921.00 Office Supplies and Expense} \times \text{Administrative Transfer Rate}$$

1 Includes labor hours directly charged to specific construction projects

2 Includes labor hours directly charged to specific construction projects and excludes nonproductive hours such as holiday, sick, vacation, military leave, jury duty, etc.

Exhibit VII - cont'd.

CALCULATION OF ADMINISTRATIVE TRANSFER RATES

II.	921.00 Office Supplies and Expense Account

TIME STUDY RESULTS:

Administrative transfer rates:

For the one month time study period ended June 30, 1996,

$$6\% = \frac{1{,}533.09 \text{ Hours}}{26{,}933.80 \text{ Hours}}$$

For the one month time study period ended July 31, 1996,

$$5\% = \frac{1{,}459.54 \text{ Hours}}{31{,}154.80 \text{ Hours}}$$

Administrative costs allocable to construction:

For the one month time study period ended June 30, 1996,

$$\$28{,}307 = \$471{,}785.64^{1} \times 6\%$$

For the one month time study period ended July 31, 1996,

$$\$25{,}169 = \$503{,}388.75^{2} \times 5\%$$

1 Source is the general ledger for the month of June 1996.

2 Source is the general ledger for the month of July 1996.

Appendix A

HAWAIIAN ELECTRIC COMPANY, INC.

INSTRUCTIONS FOR THE COMPLETION OF WEEKLY TIME SHEETS

1. Please indicate what period the timesheet is being prepared for (i.e., week ending July 5, 1996).
2. Your name (Please print.)
3. Your job title
4. Your employee identification number
5. Please indicate the activity code and/or work order number that you are charging and briefly describe the tasks that you performed each working day. If possible, please indicate whether each task is construction related by placing a check mark next to the construction task performed.
6. Indicate the amount of time (**in half hours**) that you spent on each task described in step 6 above.
7. Calculate the total hours for each task described.
8. Calculate the total hours worked for each day.
9. Calculate the total hours worked by category (e.g., total productive straight time, vacation, holiday, sick, paid and/or unpaid overtime, and other non-productive time (e.g., jury duty, military leave, etc.) for the week).
10. Sign your name and date and turn in your timesheet to your supervisor.

Thank you for your assistance in the performance of our time study. If you should have any questions in completing the timesheet, please feel free to call Carrie Lohman of KPMG Peat Marwick LLP at 541-9303.

(Note that the time sheets need to be completed and submitted to KPMG on a weekly basis for the 2 month period from June 1st through July 31st).

(SEE COPY OF THE WEEKLY TIMESHEET ON PAGE 59)

HAWAIIAN ELECTRIC COMPANY, INC.

WEEKLY TIME SHEET

PERIOD END	NAME	JOB TITLE	EMPLOYEE NO.

Description of Work	Activity Code/ Work Order No.	Check here if construction related	TIME DISTRIBUTION FOR PERIOD							Total Hours Worked
			MON	TUE	WED	THU	FRI	SAT	SUN	
Total Hours										

Employee Signature/Date

Authorizing Signature/Date

Productive Straight Time	
Vacation	
Holiday	
Sick	
Paid/Unpaid Overtime	
Other Non-Productive Time	
TOTAL	

Completing this weekly time sheet will help HECO comply with an order from the Hawaii Public Utilities Commission in Docket No. 7700. The order requires that HECO's next rate case estimate of administrative costs transferred to construction be supported by a time study or survey. Thank you for participating in this time study.

CA-IR-257
DOCKET NO. 04-0113
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HAWAIIAN ELECTRIC COMPANY, INC.

Administrative Transfer Study
Updated 2004

2004 Update of KPMG A Transfer to Construction Rates

		naruc 920 A&G labor				naruc 921 A&G non-labor		
		A	B	C = A × B	D = A - C	G	H = G × B	I = G - H
	Cost Categories	Cost Pool Total: Jan-Mar 2004 charges to naruc 920	% to capital	Construction	Non-construction	Total hours: Jan-Mar 2004 charges to 920	Construction	Non-construction
PAD	Invoice Payment Clerk	$6,789.47	18.13%	$1,230.93	$5,558.54	300.00	54.39	245.61
PAD	Accounts Payable and Disbursements Clerk	$6,842.51	18.13%	$1,240.55	$5,601.96	272.50	49.40	223.10
PAD	Accounting Clerk II	$4,342.37	18.13%	$787.27	$3,555.10	279.25	50.63	228.62
PAD	Accounting Clerk II	$4,587.28	18.13%	$831.67	$3,755.61	295.00	53.48	241.52
PAD	Accounting Clerk III	$8,225.62	18.13%	$1,491.30	$6,734.32	433.00	78.50	354.50
PAD	Accounting Clerk III	$603.86	18.13%	$109.48	$494.38	32.00	5.80	26.20
PAT	Associate Plant Accountant	$11,857.46	n/a	$8,153.62	$3,703.84	461.00	317.00	144.00
PAT	Plant Accounting Clerk	$11,186.54	n/a	$10,897.76	$288.78	445.50	434.00	11.50
PAT	Job Accounting Clerk	$11,979.39	32.50%	$3,893.30	$8,086.09	424.50	137.96	286.54
PAT	Property Accountant	$13,105.42	n/a	$12,722.37	$383.05	472.50	459.00	13.50
PAA	Lead Functional Administrator - Project Control	$14,044.16	53.15%	$7,464.47	$6,579.69	436.00	231.73	13.50
PNL	Land Agent	$6,117.57	n/a	$1,520.69	$4,596.88	197.25	48.75	148.50
PNL	Land Agent	$15,123.02	n/a	$7,713.60	$7,409.42	591.50	301.00	290.50
PNL	Land Agent	$12,246.79	n/a	$8,309.89	$3,936.90	479.75	325.50	154.25
PNL	Land Agent	$15,541.49	n/a	$9,830.85	$5,710.64	655.50	414.50	241.00
PFD	Consultant	$12,175.12	35.00%	$4,261.29	$7,913.83	470.50	164.68	305.82
PFD	Consultant	$15,714.59	35.00%	$5,500.11	$10,214.48	581.00	203.35	377.65
PFD	Consultant	$14,750.37	35.00%	$5,162.63	$9,587.74	596.50	208.78	387.72
PFD	Consultant	$14,088.97	35.00%	$4,931.14	$9,157.83	530.50	185.68	344.82
PFD	Consultant	$13,957.86	35.00%	$4,885.25	$9,072.61	512.00	179.20	332.80
PFI	Coordinator	$11,101.90	33.00%	$3,663.63	$7,438.27	541.75	178.78	362.97
PFI	Coordinator	$10,697.58	33.00%	$3,530.20	$7,167.38	494.93	163.33	331.60
PVP	Buyer	$15,657.64	19.05%	$2,982.78	$12,674.86	524.50	99.92	424.58
PVP	Buyer	$12,343.17	19.05%	$2,351.37	$9,991.80	457.25	87.11	370.14
PVP	Buyer	$10,578.43	19.05%	$2,015.19	$8,563.24	402.50	76.68	325.82
PVP	Buyer	$12,764.21	19.05%	$2,431.58	$10,332.63	475.50	90.58	384.92
PVP	Buyer	$11,156.26	19.05%	$2,125.27	$9,030.99	232.50	44.29	188.21
PVP	Buyer	$4,080.84	19.05%	$777.40	$3,303.44	301.75	57.48	244.27
PVP	Purchasing Clerk	$5,156.23	19.05%	$982.26	$4,173.97	415.00	79.06	335.94
PVP	Purchasing Clerk	$6,609.52	19.05%	$1,259.11	$5,350.41	160.00	30.48	129.52
	Total	E $313,425.64		F $123,056.96	$190,368.68		J 4,811.04	7,469.62

E ÷ F = 39%

Total hours charged to 920 K 88,337

J ÷ K = 5%

PAD % to Capital based on number of invoices

Sum of CountOfTRANSACTION_NO		
Indicator	Total	
BC	8	
BD	31	
BE	607	
BI	102	
BN	4	
BO	8	
BP	5	
BR	3	
BT	33	
NC	3669	
ND	54	
NE	9421	
NI	3237	A
NN	54	
NP	19	
NR	166	
NS	32	
(blank)	403	
Grand Total	17856	B

A ÷ B 18.13%

PAT Labor hours other than Job Accounting Clerk

Sum of SumOfNO_OF_HOURS_L			Position			
GROUP	NARUC	WORK_ORDER_L	ASSOCIATE PLANT ACCOUNTANT	PLANT ACCOUNTING CLERK	PROPERTY ACCOUNTANT	Grand Total
G30	920			3.5	5.5	9
		CR000395 non capital	68		6	74
		FI000494 capital	317	434	448	1199
		FI000515 non capital	76	8	2	86
		FI000544 capital			11	11
G30 Total			461	445.5	472.5	1379
Grand Total			461	445.5	472.5	1379

PAT Labor dollars other than Job Accounting Clerk

Sum of SumOfTRAN_AMOUNT			Position			
GROUP	NARUC	WORK_ORDER_L	ASSOCIATE PLANT ACCOUNTANT	PLANT ACCOUNTING CLERK	PROPERTY ACCOUNTANT	Grand Total
G30	920			87.9	161.05	248.95
		CR000395 non capital	1749.04		172.44	1921.48
		FI000494 capital	8153.62	10897.76	12418.75	31470.13
		FI000515 non capital	1954.8	200.88	49.56	2205.24
		FI000544 capital			303.62	303.62
G30 Total			11857.46	11186.54	13105.42	36149.42
Grand Total			11857.46	11186.54	13105.42	36149.42

PAT Job Accounting Clerk

	% to capital	Total hours per month	Construction	Non-Construction
Intercompany Billings	non-construction	40	0	40
OCARS transfer	non-construction	4	0	4
Error corrections	3/4 construction	8	6	2
Transfer of charges	39% construction	40	15.6	24.4
Journal entries	10% construction	4	0.4	3.6
PowerPlant (post workorders, file)	construction	2	2	0
Log and enter in Ellipse (stop AFUDC, final close, inactivating projects, date in svc, etc.)	construction	8	8	0
Requests for project & workorder information	construction	20	20	0
Misc	non-construction	34	0	34
Total		160	52	108
			32.5%	67.5%

LFA Project Control
% to Capital based on number of capital projects to total projects

Count of PROJECT_NO		
Ind	Total	
**	1	
BD	48	
BE	682	
BI	227	
BN	189	
BO	5	
BP	11	
BT	2	
NA	1	
NC	141	
ND	36	
NE	2130	
NI	4211	A
NN	33	
NP	36	
NR	168	
NS	2	
Grand Total	7923	B

A ÷ B 53.15%

PNL Capital Labor Dollars
Work Orders: LA000008 and LA000015

Sum of SumOfTRAN_AMOUNT			Position				
GROUP	NARUC	WORK_ORDER_L	LAND AGENT 1	LAND AGENT 2	LAND AGENT 3	LAND AGENT 4	Grand Total
G30	910	IT000247		62.32			62.32
	910 Total			62.32			62.32
	920			162.24		584.03	746.27
		AD000417		413.76			413.76
		LA000002	321.85		751.56		1,073.41
		LA000003	128.21	78.11		72.68	279.00
		LA000004	15.32	904.41			919.73
		LA000006		51.94	277.14	53.76	382.84
		LA000007	691.70	685.16	1,313.61	1,051.34	3,741.81
		LA000008		311.12		350.44	661.56
		LA000009	370.41	4,027.25	1,274.01	3,893.91	9,565.58
		LA000010	1,621.54	505.66	86.31	42.72	2,256.23
		LA000011	740.29		110.97	12.20	863.46
		LA000012	429.11		123.30		552.41
		LA000013	232.48				232.48
		LA000014	45.97	580.89			626.86
		LA000015	1,520.69	7,402.48	8,309.89	9,480.41	26,713.47
	920 Total		6,117.57	15,123.02	12,246.79	15,541.49	49,028.87
	9302	AD001342		36.79			36.79
	9302 Total			36.79			36.79
G30 Total			6,117.57	15,222.13	12,246.79	15,541.49	49,127.98
G60	1861	EE003858		82.20			82.20
		LA000132	7.44	70.88			78.32
		LA000194		32.21			32.21
		LA000200		32.37			32.37
		LA000206				12.42	12.42
	1861 Total		7.44	217.66		12.42	237.52
G60 Total			7.44	217.66		12.42	237.52
G80	184	AD000417		43.22			43.22
		AD001309		509.21			509.21
	184 Total			552.43			552.43
G80 Total				552.43			552.43
Grand Total			6,125.01	15,992.22	12,246.79	15,553.91	49,917.93

Total
2.5
2.5
32
6.25
0.25
10
36
4.75
145
27
3.25
76.5
29
19
7.5
4.75
2.75
1924
1.5
1.5
1928
3.25
3
1.25
1.25
0.5
9.25
9.25
1.75
9.75
21.5
21.5
9.75

PFD and PFI % to capital

Analysis Period = January 1, 2004 through March 31, 2004
Data taken from "Productive Time" tab in this file

Consultants (five) [PFD]

a	Total Hours Spent on Construction Recruitment	441	
b	Total Hours Spent on NonConstruction Recruitment	830	
c	Total Hours Spent on Recruitment	1271	
d	% of time spent on Construction Recruitment (a/c)	35%	
e	Monthly hours spent on Construction Recruitment (a/3)		147
f	Monthly productive hours per Consultant*		150
	*time spent on all activities; does not include sick, vacation, holidays, etc.		
g	Equivalent # of positions tied to Construction Recruitment (e/f)		0.98

Assistants (two) [PFI]

g	Total Hours Spent on Construction Recruitment	273	
h	Total Hours Spent on NonConstruction Recruitment	552	
i	Total Hours Spent on Recruitment	825	
	% of time spent on Construction Recruitment	33%	
j	Monthly hours spent on Construction Recruitment (g/3)		91
k	Monthly productive hours per Assistant*		153
	*time spent on all activities; does not include sick, vacation, holidays, etc.		
l	Equivalent # of positions tied to Construction Recruitment		0.60

Formula for determining productive hours

		Consultant	Assistant
m	Annual hours available per employee	2096	2096
	Less:		
n	Holidays	120	120
o	Ave. vacation	140	100
p	Sick estimate	40	40
q		300	260
r	Annual productive hours per employee (m-q)	1796	1836
s	Monthly productive hours per employee (r/12)	150	153

PVP % to capital based on number of capital purchase requsitions

Count of ALLOC_PC		
Indicator	Total	
BD	4	
BE	50	
NC	67	
NE	350	
NI	112	A
NP	1	
NR	4	
Grand Total	588	B

A ÷ B 19.05%

CA-IR-321

Ref: HECO T-12 pages 13–15.

Please provide copies of each decision or resolution referenced on pages 13-15.

HECO Response:

The following decisions or resolutions, attached as pages 2 through 362, are listed as follows:

- Resolution on State Commission Responses to the Natural Gas Supply Situation, July 2003 (pgs. 2-3)
- Resolution on Gas and Electric Energy Efficiency, July 2004 (pgs. 4-5)
- State of California Energy Action Plan, May 8, 2003 (pgs. 6-17)
- State of California Public Utilities Commission Decision No. 03-06-032, June 6, 2002 (pgs. 18-131)
- State of New Jersey Board of Public Utilities Energy Final Decision & Order (pgs. 132-209)
- State of New Jersey Energy Final Order, May 17, 2004 (pgs. 210-362)

Resolution on State Commission Responses to the Natural Gas Supply Situation

[redacted]

increasingly interdependent; and

WHEREAS, The nation is facing higher gas prices and increasing volatility of gas prices; and

WHEREAS, The growth in demand for gas is increasingly being driven by the demand for gas-fueled electric generating units; and

WHEREAS, The demand for natural gas is expected to increase by approximately 50% over the next two decades, and, as demand increases, gas prices are likely to stay high at least in the short-run; and

WHEREAS, Higher gas prices are likely to lead to higher electricity prices, especially in those areas where gas-fired units set the marginal wholesale price of electricity; and

WHEREAS, These economic fundamentals are likely to lead to

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its July 2003 Summer Meetings in Denver, Colorado supports the July 2003, call of the Department of Energy which encourages State and Federal Regulatory Commissions to revisit the level of support and incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response in both gas and electricity markets.

Sponsored by the Committee on Energy Resources and the Environment

Adopted by the NARUC Board of Directors July 30, 2003

Resolution on Gas and Electric Energy Efficiency

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review and reconsider the level of support and incentives for existing gas and electric utility programs designed

[redacted]

to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response in both gas and electricity markets; *and*

WHEREAS, The National Petroleum Council (NPC), in its September 25, 2003 report on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*, found that greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility and recommended all sectors of the economy work toward improving demand flexibility and efficiency; *and*

WHEREAS, The NPC, in its report, identified key elements of the effort to maintain and continue improvements in the efficient use of electricity and natural gas, including (but not limited to):

(i) enhanced and expanded public education programs for energy conservation, efficiency, and weatherization,

(ii) DOE identification of best practices utilized by States for low-income weatherization programs and to encourage nation-wide adoption of these practices,

(iii) a review and upgrade of the energy efficiency standards for buildings and appliances (to reflect current technology and relevant life-cycle cost analyses) to ensure these standards remain valid under potentially higher energy prices

(iv) promote the use of high-efficiency consumer products including advanced building materials, Energy Star appliances, energy "smart" metering and information control devices

(v) on-peak electricity conservation to minimize the use of gas-fired electric generating plants,

(vi) the use of combined-cycle gas-fired electric generating units instead of less-efficient gas-fired boilers, and

(vii) clear natural gas and power price signals; and

(viii) remove regulatory and rate structure incentives to inefficient use of natural gas and electricity; and

WHEREAS, The NARUC, at its November 2003 annual convention, adopted a *Resolution*

WHEREAS, The American Council for an Energy-Efficient Economy ("ACEEE"), in its

[redacted]

Energy Efficiency Programs, (i) identified States and utilities with programs that many would consider best practice or model programs for all types of natural gas customers and all principal natural gas end-use technologies, and (ii) found that these programs are concentrated in relatively few States and regions and could be expanded in other parts of the country to great benefit; *and*

WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the ACEEE have recently adopted a Joint Statement noting that traditional rate structures often act as disincentives for natural gas utilities to aggressively encourage their customers to use less gas. Therefore, the NRDC, AGA, and the ACEEE have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales; *now therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility

Adopted

STATE OF CALIFORNIA

CONSUMER POWER AND CONSERVATION FINANCING AUTHORITY

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

PUBLIC UTILITIES COMMISSION

ENERGY ACTION PLAN

California is a diverse and vibrant society. The fifth largest economy in the world, California's population is expected to exceed 40 million by 2010. California's economic prosperity and quality of life are increasingly reliant upon dependable, high quality, and reasonably priced energy. Following the biggest electricity and natural gas crisis in its history, the state is well aware of the need for stable energy markets, reliable electricity and natural gas supplies, and adequate transmission systems. Looking forward, it is imperative that California have reasonably priced and environmentally sensitive energy resources to support economic growth and attract the new investment that will provide jobs and prosperity throughout the state.

California's principal energy agencies have joined to create an Energy Action Plan. It identifies specific goals and actions to eliminate energy outages and excessive price spikes in electricity or natural gas. These initiatives will send a signal to the market that California is a good place to do business and that investments in the more efficient use of energy and new electricity and natural gas infrastructure will be rewarded. This approach recognizes that California currently has a hybrid energy market and that state policies can capture the best features of a vigorous, competitive wholesale energy market and renewed, positive regulation. This approach will be ever mindful of the need to keep energy rates affordable, and is sensitive to the implications of energy policy on global climate change and the environment generally.

While this Plan lays out specific actions, it is a living document. It is a blueprint that is subject to change over time. The agencies will use it to give their efforts direction, focus, and precision, but some of the specific actions cited are subject to further proceedings so may need to be fine-tuned or changed to best meet the overall goals.

Adopted

Energy Action Plan Goal

The goal of the Energy Action Plan is to:

> **Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.**

The energy agencies intend to achieve this through six specific means:

- Meet California's energy growth needs while optimizing energy conservation and resource efficiency and reducing per capita electricity demand.
- Ensure reliable, affordable, and high quality power supply for all who need it in all regions of the state by building sufficient new generation.
- Accelerate the state's goal for renewable resource generation to 2010.
- Upgrade and expand the electricity transmission and distribution infrastructure and reduce the time before needed facilities are brought on line.
- Promote customer and utility owned distributed generation.
- Ensure a reliable supply of reasonably priced natural gas.

The Agencies are Accountable for Stewardship of California's Energy Future

The state's principal energy agencies are committed to active and continued cooperation. This is unprecedented. To implement this Energy Action Plan agencies pledge:

- To discuss critical energy issues jointly through open meetings and ongoing informal communication.
- To share information and analyses to minimize duplication, maximize a common understanding and ensure a broad basis for decision-making.
- To bring joint policy recommendations about major energy issues to the Governor and Legislature.

The state needs to guide development of the energy system in the public's best long-term interest, to anticipate potential problems, and to make timely decisions to resolve problems. Specifically, the agencies commit to:

- Provide decision-makers impartial assessments of the state's immediate and long-term electricity and natural gas demands, resources, and prices.
- License and, where necessary, fund construction of new energy facilities that are consistent with the reliability, economic, public health, and environmental needs of the state.
- Ensure that the utilities are able to carry out their obligation to serve, including having adequate reserves, recognizing this is a critical component of the current hybrid energy system.
- Restore investor and private sector confidence in California's energy markets.

Adopted

- Develop an "early warning" system to alert policy makers of potential future problems.
- Work with FERC to redesign market rules and prevent manipulation of the energy markets.
- Partner with governmental and other groups in western North America to pursue commonly held energy goals.
- Make continuing progress in meeting the state's environmental goals and standards, including minimizing the energy sector's impact on climate change.

Shared Principles and Strategies Will Guide this Stewardship

Achieving the overall goal and implementing the proposed actions require close cooperation between the state's energy agencies and means establishing and following common principles and strategies. In particular, the agencies intend to use market forces and regulatory approaches to operate the system in the best, long-term interest of the public: the consumers, the ratepayers, and the taxpayers. This means agency actions will attract private investment into California's energy infrastructure to stretch and leverage public funds and consumer dollars. The agencies must also provide appropriate regulatory guidance, price signals, and incentives to all Californians to use energy efficiently. The agencies will achieve rate stability and provide affordable energy, particularly for low-income consumers, through progressive rate design.

To protect the public's health and safety and ensure our quality of life, the agencies support the most cost-effective and environmentally sound strategies, including consideration of global climate change. The agencies also will work to ensure that low-income populations do not experience disproportionate adverse impacts from the development of new energy systems.

The Agencies' Approach Will be Open and Timely

Achieving the overall goal requires thoughtful planning, followed by specific, timely actions. This process begins with an ongoing assessment of the current and future energy system and the state's economic needs. It must consider a range of risks and uncertainties and must identify and inform policy makers of potential shortfalls and vulnerabilities. The agencies and state policy makers need to respond by carefully considering available options, balancing costs and benefits to meet state goals, selecting policy choices, and devising actions to implement those policy choices.

The result must be a set of interrelated actions that complement each other, provide risk protection, and eliminate the costs and conflicts that would occur if each agency pursued isolated, uncoordinated objectives. Each agency will need to implement the action plan in its individual proceedings but in concert with each other.

For the action plan to achieve the desired outcomes, it must rely on a common vision and be based on an integrated energy resource plan indicative of the state's future energy needs. The Energy Commission's integrated energy assessment process, as set forth by the Governor and Legislature last year in SB 1389, represents a critical

step in identifying future statewide energy needs. The agencies will participate in this process, assessing demand growth and available supply, and balancing various state policy objectives to determine the combination of conservation and infrastructure investments that best meet California's short- and long-term needs. The Public Utilities Commission and the Power Authority will carry out their energy-related duties and responsibilities based upon the information and analyses contained in the assessment.

The Action Plan envisions a "loading order" of energy resources that will guide decisions made by the agencies jointly and singly. First, the agencies want to optimize all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand. Second, recognizing that new generation is both necessary and desirable, the agencies would like to see these needs met first by renewable energy resources and distributed generation. Third, because the preferred resources require both sufficient investment and adequate time to "get to scale," the agencies also will support additional clean, fossil fuel, central-station generation. Simultaneously, the agencies intend to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centers and the interconnection of new generation.

Energy Services are Growing, are Essential, and the Delivery Systems are Complex

As a context for this plan, Californians must understand the essential and complex nature of the state's energy resources. Currently the state uses 265,000 gigawatt-hours of electricity per year. Consumption is growing 2 percent annually. Over the last decade, between 29 percent and 42 percent of California's in-state generation used natural gas. Another 10 - 20 percent was provided by hydroelectric power that is subject to significant annual variations. Almost one third of California's entire in-state generation base is over 40 years old. California's transmission system is aging also. While in-state generation resources provide the majority of California's power, California is part of a larger system that includes all of western North America. Fifteen to thirty percent of statewide electricity demand is served from sources outside state borders.

Peak electricity demands occur on hot summer days. California's highest peak demand was 52,863 megawatts and occurred July 10, 2002. Peak demand is growing at about 2.4 percent per year, roughly the equivalent of three new 500-megawatt power plants. Residential and commercial air conditioning represent at least 30 percent of summer peak electricity loads.

California's demand for natural gas also is increasing. Currently the state uses 2 trillion cubic feet of natural gas per year. Historically the primary use of this fuel was for space heating in homes and businesses. Electricity generation's dependence on relatively clean-burning natural gas now means that California's annual natural gas use by power plants is expected to increase. Overall, natural gas use is growing by

Adopted

Six Actions

The agencies propose six sets of actions of critical importance that need to be undertaken now. These are:

I. Optimize Energy Conservation and Resource Efficiency

California should decrease its per capita electricity use through increased energy conservation and efficiency measures. This would minimize the need for new generation, reduce emissions of toxic and criteria pollutants and greenhouse gases, avoid environmental concerns, improve energy reliability and contribute to price stability. Optimizing conservation and resource efficiency will include the following specific actions:

1. Implement a voluntary dynamic pricing system to reduce peak demand by as much as 1,500 to 2,000 megawatts by 2007.[1]
2. Improve new and remodeled building efficiency by 5 percent.[2]
3. Improve air conditioner efficiency by 10 percent above federally mandated standards.[3]
4. Make every new state building a model of energy efficiency.
5. Create customer incentives for aggressive energy demand reduction.
6. Provide utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects.
7. Increase local government conservation and energy efficiency programs.
8. Incorporate, as appropriate per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction.
9. Encourage companies that invest in energy conservation and resource efficiency to register with the state's Climate Change Registry.

II. Accelerate the State's Goal for Renewable Generation

In 2002, the Governor signed the Renewable Portfolio Standard (RPS), SB 1078. This standard requires an annual increase in renewable generation equivalent to at least 1% of sales, with an aggregate goal of 20% by 2017. The state is aggressively implementing this policy, with the intention of accelerating the completion date to 2010, and will:

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[1]. California is actively evaluating and implementing such pricing systems in a CPUC rulemaking (R.02-06-001).

[2] The Energy Commission's 2005 building standards, to be adopted in 2003, when combined with training and enforcement, are expected to reduce energy needs in new buildings by approximately 5 percent.

[3] New federal appliance standards will increase air conditioner efficiency by approximately 20 percent, but if California were granted a waiver from federal standards, by 2007 California air conditioner efficiency would increase another 10 percent.

Adopted

1. Add a net average of up to 600 MW of new renewable generation sources annually to the investor-owned utility resource portfolio.[4]
2. Establish by June 30, 2003, key RPS implementation rules, including market price benchmarks, standard contract terms, flexible compliance and penalty mechanisms, and bid ranking criteria under the "least cost-best fit" rubric. Other key RPS rules will be developed and refined throughout 2003.
3. Facilitate an orderly and cost-effective expansion of the transmission system to connect potential renewable resources to load.
4. Initiate the development of RPS compliance rules for energy service providers and community choice aggregators.
5. Coordinate implementation with all relevant state agencies and with municipal utilities to facilitate their achievement of the standard.

III. Ensure Reliable, Affordable Electricity Generation

The state needs to ensure that its electrical generation system, including reserves, is sufficient to meet all current and future needs, and that this reliable and high quality electricity comes without over-reliance on a single fuel source and at reasonable prices. To these ends the state will:

1. Add new generation resources to meet anticipated demand growth, modernize old, inefficient and dirty plants and achieve and maintain reserve levels in the 15 percent-18 percent range.[5] Current estimates show a statewide need for 1500 - 2000 MW per year.[6]
2. Finance a few critical power plants that the agencies conclude are necessary and would not otherwise be built. An estimated 300 MW of peaking capacity located in critical areas is needed to provide local reliability, help achieve adequate reserves, and reduce congestion and the need for new transmission lines.[7]
3. Work with the California Independent System Operator (CAISO) to implement generator maintenance standards and an oversight process to support coordinated availability of generation.[8]

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[4] Electricity sales by the Investor-owned utilities totaled about 169,000 GWh in 2001. The renewables portfolio standard requires an annual increase in renewable generation equivalent to 1 percent of sales, or about 1,700 GWh. Assuming a capacity factor of about 50 percent, this is roughly equivalent to 385 MW. Accelerating achievement of the RPS goal to 20 percent by 2010 would mean adding 4,200 MW of renewables over 7 years, or 600 MW (1.6 percent) per year. California is implementing the Renewable Portfolio Standard for the Investor-owned utilities in a PUC rulemaking (R.01-10-024).

[5] The Western Electricity Coordinating Council (WECC) has established minimum operational requirements of loss-of-load probability of no more than one day in ten years. Current information suggests that the WECC criteria can be met with approximately 15 – 18 percent reserve margins.

[6] Peak demand growth is expected to be approximately 1,400 MW per year for the next two years, depending on weather and other factors. California is evaluating statewide generation resource needs in the CEC development of the Integrated Energy Policy Report (02-IEP-01).

[7] The CAISO in 2002 identified generation-deficient areas and sub-areas within its control area, such as the greater Bay Area, Humboldt, Battle Creek and Vaca Dixon. Although some of these constraints may be solved by transmission improvements, it may prove more cost-effective to add new generation in some areas perhaps utilizing the CPA's authority to finance new power plants.

[8] California is undertaking this effort in a PUC rulemaking (R.02-11-039).

Adopted

4. Work with the CAISO to ensure the development of a workable, competitive wholesale energy market that has meaningful market power mitigation rules.
5. Monitor the electricity market to identify any exercise of market power and manipulation, and work to improve FERC-established market rules to correct any observed abuses.

IV. Upgrade and Expand the Electricity Transmission and Distribution Infrastructure

Reliable and reasonably priced electricity and natural gas, as well as increasing electricity from renewable resources, are dependent on a well-maintained and sufficient transmission and distribution system. The state will reinvigorate its planning, permitting, and funding processes to assure that necessary improvements and expansions to the distribution system and the bulk electricity grid are made on a timely basis:

1. The agencies will collaborate, in partnership with other state, local, and non-governmental agencies with energy responsibilities, in the California Energy Commission's integrated energy planning process to determine the statewide need for particular bulk transmission projects. This collaboration will build upon the California Independent System Operator's annual transmission plan and evaluate transmission, generation and demand side alternatives. It is intended to ensure that state objectives are evaluated and balanced in determining transmission investments that best meet the needs of California electricity users.
2. The Public Utilities Commission will issue an Order Instituting Rulemaking to propose changes to its Certificate of Public Convenience and Necessity process, required under Public Utilities Code § 1001 et seq., in recognition of industry, marketplace, and legislative changes, like the creation of the CAISO and the directives of SB 1389. The Rulemaking will, among other things, propose to use the results of the Energy Commission's collaborative transmission assessment process to guide and fund IOU-sponsored transmission expansion or upgrade projects without having the PUC revisit questions of need for individual projects in certifying transmission improvements.
3. The Public Utilities Commission will ensure that IOUs build out and properly staff and maintain distribution systems to meet California's growth, provide reliable service, and stand ready to restore service after unplanned distribution system outages.
4. The Energy Commission will work with municipal utilities to help ensure completion of transmission expansion or upgrade projects in their systems for which the collaborative transmission assessment process finds a need.

V. Promote Customer and Utility Owned Distributed Generation

Distributed generation is an important local resource that can enhance reliability and provide high quality power, without compromising environmental quality. The state is promoting and encouraging clean and renewable customer and utility owned distributed generation as a key component of its energy system. Clean distributed generation should enhance the state's environmental goals. This determined and

aggressive commitment to efficient, clean and renewable energy resources will provide vision and leadership to others seeking to enhance environmental quality and moderate energy sector impacts on climate change. Such resources, by their characteristics, are virtually guaranteed to serve California load. With proper inducements distributed generation will become economic.

1. Promote clean, small generation resources located at load centers.
2. Determine whether and how to hold distributed generation customers responsible for costs associated with Department of Water Resources power purchases.
3. Determine system benefits of distributed generation and related costs.
4. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program.
5. Standardize definitions of eligible distributed generation technologies across agencies to better leverage programs and activities that encourage distributed generation.
6. Collaborate with the Air Resources Board, Cal-EPA and representatives of local air quality districts to achieve better integration of energy and air quality policies and regulations affecting distributed generation.
7. The agencies will work together to further develop distributed generation policies, target research and development, track the market adoption of distributed generation technologies, identify cumulative energy system impacts and examine issues associated with new technologies and their use.

VI. Ensure Reliable Supply of Reasonably Priced Natural Gas

The high and volatile price of natural gas contributed significantly to the energy crisis in 2000-2001, and concerns about manipulation of the market and scarcity persist. The Governor's Natural Gas Working Group was formed to monitor natural gas demand, supply and price issues and facilitate the construction of California infrastructure projects. Yet California remains vulnerable to the volatile spot market. The agencies will pursue the following actions:

1. Identify critical new gas transmission, distribution and storage facilities needed to meet California's future needs.
2. Monitor the gas market to identify any exercise of market power and manipulation, and work to improve FERC-established market rules to correct any observed abuses.
3. Evaluate the net benefits of increasing the state's natural gas supply options, such as liquefied natural gas.
4. Support electric utilities and gas distribution companies entering into longer-term contracts as a hedge against volatile and high spot market prices.

In implementing this plan, the agencies are mindful that energy services – both natural gas and electric – are essential to every Californian's general welfare and to the health of California's economy. As actions to improve the reliability of these services are considered, the agencies will each take into account the effect the action will have on energy expenditures, the environment and climate change, and the overall economy. Alternatives to proposed actions will be evaluated in an integrated

Adopted

fashion, consider the cost of action or inaction, and consider the equitable distribution of costs among customer classes and groups.

While implementation of this Action Plan represents a challenge, it is an important step for the agencies to take together to help achieve the state's overall goal of adequate, reliable, and reasonably priced electrical power and natural gas supplies.

Adopted May 8, 2003 by a 3-2 vote of the CPUC. Dissent of Commissioners Lynch and Wood attached.

Adopted April 30, 2003 by unanimous vote of the CEC.

Adopted April 18, 2003 by unanimous vote of the CPA.

Adopted

Dissent of Commissioners Lynch and Wood to the Energy Action Plan, May 8, 2003, Item CR-2

Coordination among agencies is good. Cooperation among agencies is good. Planning is good. All of these aspects of the Action Plan are positive. However,

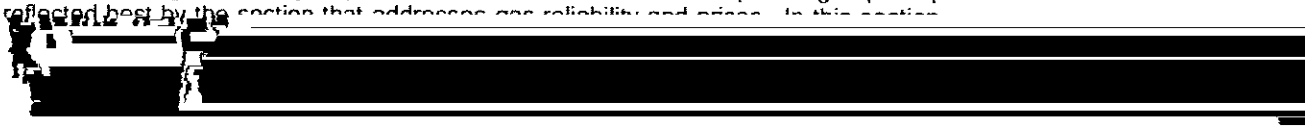
there is a difference of emphasis and philosophy that makes the document unsupportable at present. Our focus is on consumers. The Plan's focus is on competition. We want stability, predictability, consumer protection, low prices, environmental preservation, and regulatory fairness. The Plan talks about markets. We want to re-establish and strengthen the utilities' obligation to serve. The Plan wants to cultivate hybrid markets. We want to promote distributed renewables and new efficient, low-polluting, utility-owned generating plants. The Plan offers generic support for customer-owned generation in any form.

We want to ensure that utilities make wise economic choices when procuring or generating power. The plan wants to use "proper inducements" to help various kinds of distributed generation technologies to become economical. This is a euphemism for ratepayer provided subsidies. We want to restore investor confidence in California's regulated utilities. The plan talks of restoring investor confidence in California's energy markets. Stable energy markets, reliable energy supplies and adequate transmission systems are all

Adopted

attempts to prescribe specific outcomes for matters that require evidentiary records and careful scrutiny, it goes too far.

What is good and appropriate in terms of coordination and planning is perhaps reflected best by the section that addresses gas reliability and prices. In this section



the agencies commit to identify needed new facilities, monitor the market to guard against the exercise of market power, evaluate the net benefits of new supply options such as LNG, and support the appropriate use of long-term supply contracts to stabilize prices. These are broad goals that could appropriately frame the activities of the agencies without prejudging the outcome of formal proceedings.

But what the ad hoc subcommittee and this commission cannot do is to form advance commitments to decide in a certain way matters that must come before the agency. This is not a limitation of philosophy or style. It is a limit imposed by law.

Here are some examples of ways in which the Plan moves beyond appropriate planning and coordination. It sets goals for peak demand reduction through a variable pricing system. It does this, although it acknowledges that the Commission is actively evaluating such pricing systems in a pending proceeding. It declares an appropriate capacity range for new electric resource additions and an appropriate range for reserve margins although the Commission has yet to take the steps required by AB 57 before establishing such goals. Similarly, it jumps ahead of the AB 57 process to declare a level of needed new peaking capacity.

It declares that three specific new transmission projects are needed even though the Commission is required by law to make record-based needs assessments under Section 1001 and CEQA. One of the projects, the Path 15 upgrade, is the subject of two draft decisions that are currently pending before the Commission. The other two – a second Palo Verde-Devers line and an expansion to serve wind farms in Tehachapi -- are as-of-yet not even the subject of formal applications. It announces that sufficient new transmission must be built to ensure high quality power supply throughout the state, although those nice-sounding words suggest that the entire state should be wired as if it is the Silicon Valley. It prejudges the Commission's decision about departing load customers and pledges the adoption of exemptions for various technologies at levels not represented by any Commission orders.

We fear that some commissioners show an impatience for action that reflects more than a desire for government to act quickly. We are concerned that it reflects a desire to lock the agency into positions and commitments before it is burdened by such niceties as the facts in an evidentiary record and parties' interpretations of the law and policy.

Adopted

approved, then they would not have included words calling for their approval. As the disclaimer further states, this is a "blueprint", intended to provide "direction, focus, and precision". The obvious goal is to predetermine either the specific outcome or the substantive direction of various proceedings currently pending, or expected to be filed. We cannot pledge, in advance, to lower someone's rates in a certain way, deny someone's complaint, or approve someone's petition. Nor can we skirt around pending proceedings to create new programs, set reserve margins or declare that certain new facilities are needed. To do so would be unfair. It would breed cynicism [redacted]

adoption of the Energy Action Plan.

/s/ LORETTA M. LYNCH
Loretta M. Lynch
Commissioner

CARL WOOD
Carl Wood
Commissioner

San Francisco, California
May 8, 2003

STATE OF CALIFORNIA
PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

GRAY DAVIS, *Governor*

June 6, 2003

TO: ALL PARTIES OF RECORD IN ORDER INSTITUTING RULEMAKING 02-06-016

Decision 03-06-032 is being mailed without the written Dissents of Commissioner Lynch and Commissioner Wood. The Dissents will be mailed separately.

Very truly yours,

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:acb

Attachment

ALJ/LTC/acb

Mailed 6/6/03

Decision **03-06-032** June 5, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	Rulemaking 02-06-001 (Filed June 6, 2002)

INTERIM OPINION IN PHASE 1 ADDRESSING DEMAND RESPONSE GOALS AND ADOPTING TARIFFS AND PROGRAMS FOR LARGE CUSTOMERS

INTERIM OPINION IN PHASE 1 ADDRESSING DEMAND RESPONSE GOALS AND ADOPTING TARIFFS AND PROGRAMS FOR LARGE CUSTOMERS 1

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I.Summary

This decision, the second of two decisions to be rendered in Phase 1 of this demand response rulemaking, addresses the interagency vision for advancing

[redacted]

statewide demand response goals, links the task of meeting those goals with utility procurement requirements, and adopts an initial set of [redacted]

We began this rulemaking[2] in June 2002, as a policymaking forum to develop demand response as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. At the outset we recognized the need for a strategic approach to the orderly development of demand response capability in the California energy market. To that end, we have coordinated this rulemaking exercise with decision makers from the California Energy Commission (CEC) and the CPA based on an interagency working model developed by the assigned Commissioner.[3]

That model relied upon three working groups. Of particular significance to this decision are the efforts of Working Group 1 (WG1) and Working Group 2 (WG2).[4] WG1 is comprised of agency decision makers (assigned Commissioner Michael Peevey, CEC Commissioner Arthur Rosenfeld, and CPA Director Sunne W. McPeak, also known as the "Working Group 1 principals"), supported by the

demand response vendors and consultants, energy service providers, utility workers, and the California Independent System Operator (ISO). This group, whose meetings were facilitated by agency staff supporting WG1, has developed the specific proposals we consider here.

As this decision recognizes, a robust and sound policy framework is essential as the foundation for the future development of statewide demand response programs. At the same time, the WG1 principals appreciate the need for swift action to take advantage of the real opportunity to achieve significant levels of demand reduction by Summer 2003. Balancing these factors, WG1 directed WG2 to delve into the practicalities of program and tariff development for large customers, rather than pursue additional pilot programs for such customers in Phase 1, and formalized WG2's mission as "expanding demand response capabilities by developing a tariff or set of tariffs to be used for large customers with average monthly demands of 200 kW and above."[5]

WG 1, meanwhile, focused its efforts on the development of a long-term vision for the development of demand responsiveness in California by setting a framework, developing goals, and focusing on how demand response can and should be integrated with the IOUs' overall procurement responsibilities.

All working group meetings were publicly noticed and meeting agendas were publicly available at least 48 hours prior to each meeting. The WG2 facilitators made meeting minutes available to all participants.[6] At the WG2 meetings, the facilitators encouraged broad participation in an environment where stakeholders representing a variety of views were free to provide their

[5] August 1, 2002 Ruling Following Prehearing Conference, page 4.

opinions, make proposals and presentations, share their practical experiences, and work toward collective solutions. The group's initial focus was on taking advantage of the advanced meters already installed at customer sites with monthly demands of more than 200 kW, paid for through appropriations in Assembly Bill 29 of the First Extraordinary Session of 2000-2001 (AB29X) (Stats. 2001, 1st Ex. Sess., Ch. 8, Sec. 10.2, effective April 12, 2001). The participants attempted to develop consensus around a set of "quick win" dynamic pricing proposals designed to take advantage of these existing meters and produce demand response by the Summer of 2003, but the diversity of opinion on key issues complicated this task and ultimately worked against the development of consensus.

Several parties have participated actively in the workshop process and have filed written comments on WG2 issues throughout Phase 1. These include respondents PG&E, SDG&E, and Edison (the "respondent IOUs"); the Office of Ratepayer Advocates (ORA); The Utility Reform Network (TURN); the California Consumer Empowerment Alliance (CCEA); the City and County of San Francisco (CCSF); the Department of General Services (DGS); the Alliance for Retail Energy Markets and the Western Power Trading Forum (AreM and WPTF); the Association of California Water Agencies (ACWA); the Building Owners and Managers Association of California (BOMA); the California Large Energy Consumers Association (CLECA); the California Manufacturers & Technology Association (CMTA); the Demand Reserves Providers (Ancillary Services Coalition; Celebrity Energy; DBS Industries; Robertson-Bryan, Inc.); and IMServ.

2002, supplemented the first by addressing implementation details.[7] After the WG1 principals expressed concern that the proposed offerings were inadequate to meet WG1's demand response goals,[8] the respondent IOUs significantly revised their proposals, and withdrew some of those proffered earlier. As a result, on January 16, 2003, WG2 filed its third report containing a proposal sponsored by the respondent IOUs for a statewide critical peak pricing (CPP) tariff. On January 27, 2003, the active parties filed written comments addressing all of the third report and those elements of the first two reports not superseded by the third filing. Since agency staff suggested incentives might be needed to achieve the quantitative goals proposed for demand response programs, the ALJ permitted WG2 to hold another noticed workshop focused on transitional incentives, and on March 11, 2003, WG2 presented its fourth and final report addressing this limited issue.[9] The record in Phase 1 with respect to WG2 issues was then submitted. By that time, the WG1 principals had held five noticed workshop meetings,[10] and WG 2 had held thirteen noticed workshop meetings.[11]

[7] On December 23, 2002, WG2 filed an Errata to both the November 15 and December 13 Reports.

[8] See generally WS-4 RT 284-372, the official transcript of the December 4, 2002 meeting of Working Group 1.

[9] In lieu of individually filed written comments, the parties included their comments, both supporting and dissenting, in the body of the fourth WG2 Report.

[10] WG1 met on August 26, September 16, October 15, December 4, 2002, and February 7, 2003. These meetings were officially transcribed (See WS 1 RT 1-100; WS 2 RT 101-201;

The Commission has held no hearings in Phase 1, but has proceeded via notice and comment rulemaking, with WG1 providing specific policy guidance to the active parties at key points through formally noticed meetings and rulings. Following this direction, and working through WG1 staff facilitators, the parties developed the proposals we address in Phase 1. Our decision making record in connection with WG2 issues consists of respondents' formal demand response programs/pricing options filed in compliance with the OIR; the official transcripts of five formally noticed WG1 meetings; the rulings following those meetings and written comments thereon; and the four WG2 reports and related rulings and written comments.

III. Statewide Demand Response Vision and Goals

Early on during WG1 meetings, the Principals endorsed the idea of developing a long-term "vision" and set of goals for demand response to help guide the efforts of participants in this proceeding. The aim was not to prejudge issues but instead to provide a framework and set of goals within the context of which activities in this proceeding would be set. Interagency staff supporting WG1 set out to develop this vision. An initial presentation was made during the WG1 meeting of September 16, 2002[12] with follow-up discussions during the October 15 and December 4 WG1 meetings. Revisions were made to an evolving vision statement after each WG1 meeting, and parties were asked to comment on each version in response to rulings following each WG1 meeting. Thus, there were three rounds of comment opportunities on the vision statement.[13]

[12] See presentation by John Flory attached to the transcript of the September 16, 2002 WG1 meeting.

[13] During the original round of comments prompted by the October 29 ALJ ruling, comments were filed by PG&E, TURN, ORA, CFBF, CIU, CLECA, NRDC, Invensys, Alliance to Save Energy/SVMG/CCEA, SCE, and SDG&E.

Numerous changes were made to the original vision statement as a result of those comments. The most current version of the vision statement is attached to this decision as Attachment A.

The vision statement provides a definition and simple statement of a goal, followed by objectives (reliability, lower power costs, and environmental protection), goals and principles (customer service, optionality, technology issues, IOU issues, coordination) and a timeframe (phases for proof-of-concept, phased implementation for large customers, and residential implementation).

While we do not seek formal Commission adoption of the entire vision statement in this decision, since we view it as an evolving document and work-in-progress at all times, there are several aspects of the vision that we do believe require explicit Commission endorsement in order to help direct the activities of IOUs and other parties.

In particular, since the vision statement sets a goal of meeting IOU capacity needs of five percent of system peak demand by 2007 through demand response,[14] we believe it is important to set interim megawatt (MW) targets in pursuit of that goal. We also wish to make explicit the linkage between these targets and the utilities' procurement-related obligations to be included in their procurement plans to be filed in R.01-10-024.

In order to facilitate the setting of concrete goals for demand response, during the February 7, 2003 meeting of WG1, interagency staff presented a set of proposed targets. These represent roughly an increase in 1% of demand

[14] This goal does not include (is over and above) demand response achieved through the emergency programs authorized in R.00-10-002 (interruptible rulemaking). Thus, in this decision we are referring to programs and tariffs that are triggered by price and not by emergency conditions.

response achieved between 2003 and 2007, and are summarized in the table below.

Table 1. Demand response goals

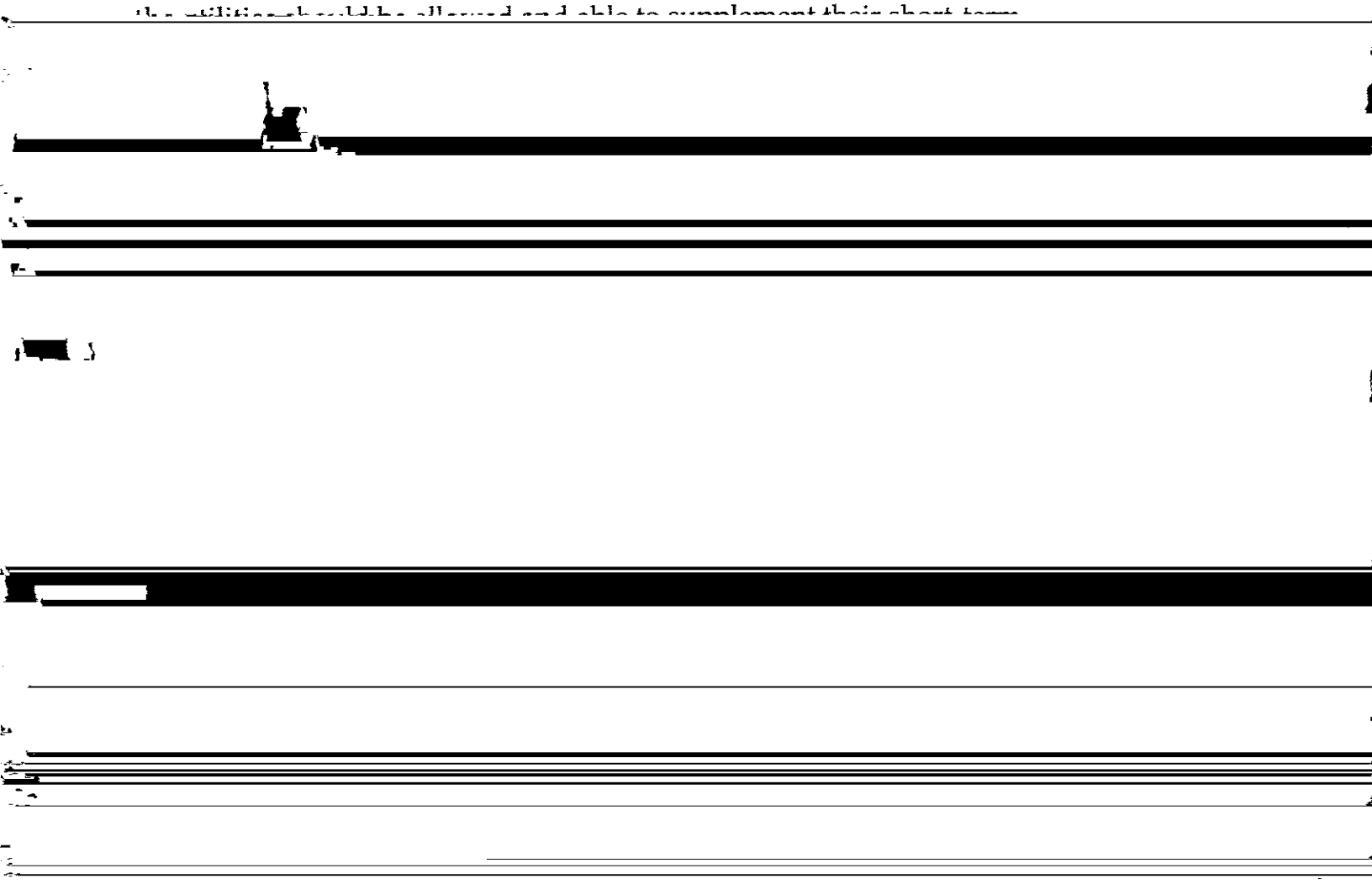
Year	PG&E	Edison	SDG&E
2003	150 MW	150 MW	30 MW
2004	400 MW	400 MW	80 MW
2005	3% of the annual system peak demand		
2006	4% of the annual system peak demand		
2007	5% of the annual system peak demand		

In their verbal comments at the February 7 WG1 meeting, the utilities responded that these targets could be a stretch, but are achievable.[15] Interagency staff further recommended that the utilities be required to include these targets in their procurement plans to be filed in R.01-10-024. To the extent that this decision is adopted after those plans are filed, the utilities should supplement or augment their filings to reflect this requirement. In particular, each utility should include the numeric targets given in the table above, along with documentation of:

- The amount of demand response (price-triggered) to be achieved by July 1 of each calendar year
- Which programs and/or tariffs the utility will rely upon to achieve the targets
- A contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals

[15] See transcript of February 7, 2003 WG1 meeting (5 WS RT 426, 430).

This means that the utilities should not contract for the equivalent amounts of generation resources and should instead rely upon demand response resources to serve load. Utilities should dispatch the tariffs and programs when they are cost-effective relative to the marginal generation costs avoidable through demand response as the utilities make short-run commitments. To the extent that the actual reliable demand response resources fall short of the goals, the utilities should be allowed and able to supplement their short-term



purchases.

We expect that during the early years, most of the demand response goals will be met by programs and tariffs for large customers, such as those we authorize in the following sections of this decision. Based on the outcome of the pilot for small customers we authorized in D.03-03-036, the utilities should eventually be able to meet more of their goals reliably through programs and tariffs for smaller customers, including air conditioner cycling programs which

response programs that are sustainable over the long term. At the outset we noted that a perfectly functioning wholesale and/or retail electricity market was not a precondition for development of demand response, and we explicitly stated the value of demand response as "...a tool in mitigating the effects of a dysfunctional market, as well as for controlling costs, even in a completely vertically integrated and regulated market."[16] However, adding this tool to our regulatory tool chest is not an easy task, and will require an iterative process as well as a multi-year commitment on the part of regulators, customers and utilities that involves the following: taking care to develop the programs that are workable and suitable for their intended purpose; listening to what the members of different customer classes tell us about their needs both explicitly and by their reaction to the programs we adopt; and both fine tuning and significantly adjusting these programs over the years, in a manner consistent with the need for stability in these programs. We cannot accomplish everything on our policy agenda in one decision, or even in a series of decisions. Instead, we must take the long-term view, even as we begin with a series of discrete steps. The challenges posed by large customer demand response are daunting and quite complex, requiring that we proceed deliberately, but with great care.

Although the WG2 participants agree on many principles, they have been unable to develop a consensus tariff proposal, given the diversity of views among large customer interests, respondents, and the other parties. As one party characterizes the situation, "to date, customer support for utility designed programs has been tepid, and utility support for third party proposals has been nonexistent."[17]

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[16] Order Instituting Rulemaking (R.02-06-001), p. 1.

[17] CMTA's Comments on WG2 Reports, p. 2.

It is clear that large customers use electricity in ways that differ fundamentally from the ways in which other customers use it. For example, their electricity usage may be an essential component of an industrial or agricultural process. This means that as they consider load shifting or load reduction, such customers must also consider distinct and significant cost issues relative to their operating requirements, whether they be manufacturers, agricultural users, or building owners.[18] All of these factors require us to make a careful assessment of the impacts of our decisions on these customers.

In retrospect, our focus on achieving a "quick win" may have made it more difficult for these customers to find common ground. At the outset, we encouraged the parties to focus on tariffs/programs that would achieve a "quick win" because we wanted to take advantage of the fact that many >200 kW customers already have advanced meters in place (due to AB29X) in order to learn how such customers would react to dynamic tariffs during Summer '03 and Summer '04, when system conditions for such a test should be ideal. However, we now know that some parties were reluctant to consider third party proposals, such as an innovative two- part RTP tariff, due to concern that such proposals could not be in place within a matter of months.[19] As a result, in Phase 1 we address a relatively limited number of demand response options. However, as we shift focus beyond 2003, we will confront some of the structural and regulatory obstacles that may be impeding customer acceptance of demand response programs, and we will carefully refine our initial efforts and design new programs that will garner long-term customer support.

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[18] See, e.g., the following parties' comments on the various WG2 Reports: ACWA; BOMA; CLECA; and CMTA.

[19] CMTA's Comments on WG2 Reports, pp. 3 – 4.

For now, this decision considers the merits of adopting CPP tariffs and a limited RTP tariff presented by SDG&E, as well as demand bidding programs – and the authorization of funding for these tariffs and programs through 2004. As these tariffs and programs will be in place well beyond 2004, our goal is to encourage as many large customers as possible to participate in them as a first step in a longer-term effort. This first step also involves careful recruitment and encouragement of participating customers, using modest incentives in the near term. The customers who participate in the tariffs/programs adopted in this decision are the vanguard of the customers who will participate in demand response programs during the coming years.

B. Design Objectives for Demand Response Programs

In its November 15th report, WG2 developed several design objectives that take into account the fact that no single program satisfies all large commercial customers.[20] Some customers can use demand bidding programs to bid load reductions into the day ahead market, thus providing the electric system with an alternative source of supply. Other customers can reduce or shift their usage in response to posted day-ahead prices or critical peak signals, both of which are embodied in dynamic tariffs. While quite different in the degree of customer commitment, each response may yield market price and reliability benefits and more efficient energy usage decisions. This is the rationale for having a "portfolio," or mix, of demand response programs that will appeal to the greatest number of customers.

For example, in Phase 1 we are considering two demand bidding programs. Both are similar in allowing customers to shed load when market

[20] WG 2 Report dated November 15, 2003, p. 4.

prices reach a set threshold. However one, the IOU DBP, is designed for customers not willing to make a firm commitment, who are paid solely for the energy reductions they actually choose to make. The other, the CPA DRP, has reservation payments scaled to firm commitments to shed load, measurement protocols to be sure that load reductions can be accurately measured, and penalties for failing to meet load reduction commitments. Some customers prefer the freedom of the former approach, while others prefer the security of a known payment stream provided by the latter. Under the design principles we adopt, it is conceivable that both features could be combined in a single offering for large customers.

C. Mandatory or Voluntary Participation?

Given the nature of large customer electricity usage, as discussed above, WG2 recommends that the 2003 tariff offerings should be voluntary. This could not have been an easy call, for mandatory programs avoid several problems endemic to voluntary programs. For example, in a voluntary setting, certain customers may elect to participate in a demand response program that benefits their particular load profile without motivating them to shift or reduce demand in any way. Other customers may simply choose not to participate in a voluntary demand response program, thereby diminishing overall demand response capability. However there are strong arguments against mandatory tariffs for large customers. Some of these customers simply are not able to respond to price signals because of the nature of their production methods. To force them onto a tariff that essentially raises their rates as they fail to respond seems unfair. And to raise their rates without a hearing is highly questionable.[21]

[21] Working Group 2 Report dated November 15, 2002, p. 32.

In view of these competing factors, the WG2 participants believe that there are too many complications to consider imposing a mandatory program on large customers in the near term.

Although TURN states that it lacked the resources to participate fully in WG2, it did file comments on the WG2 Reports, opposing the WG2 recommendation for a voluntary program for large customers. TURN cites the interruptible programs in place during 1992-2000, where customers who were confronted with the probability of interruptions after 2000 left the program in large numbers. TURN argues that large customer behavior has not changed in the past two years, and there remains a significant drop off in subscription for industrial demand reduction programs, especially for Edison, notwithstanding the utility's payment of millions of dollars of incentives over many years.[22] TURN argues that this experience demonstrates that policy makers will never be able to attract large customers to demand side programs without guaranteeing these customers both an upside financial benefit and little or no downside risk. TURN believes the Commission must adopt a mandatory program for large customers, and proposes that all customer with demand greater than 200kW who have received free advanced meters from AB29X funds, be transferred to critical peak pricing on a mandatory basis.

TURN acknowledges that some of the details of this proposal, which was first detailed in its written comments and has not been vetted in WG2, remain somewhat general. Nonetheless it believes that the proposal, along with the Commission's June 1, 2001 rate increase, which allocated significant rate

reduction goals. It believes the Commission will find, upon investigation, that there is considerable evidence that the current rate design, which includes on-peak energy surcharges in the range of $0.20/kWh, is already providing large customers with meaningful price signals to reduce demand during these periods.[23]

We are at a very early stage in looking at price responsive demand reduction programs for large customers. The experience TURN cites comes from mandatory load curtailment programs, not price responsive programs, and it is not entirely clear that large customer behavior in the one area can be extrapolated to the other. There simply is no record at this point in the proceeding to reject the WG2 consensus view and impose a mandatory CPP on large commercial customers in the near term. Further, it is unclear in the context of price-responsive programs that mandatory response is even needed, unlike emergency programs that are designed to ensure reliable system operations.

D. Program Details

In its November 15th report, WG3 presented six tariff and program proposals for our consideration, without recommending adoption of any specific one. Rather WG 2 recommended selection of a mix of the programs, consistent with the design objectives discussed earlier. Thereafter, on December 23, 2002, the respondent IOUs informed the ALJ that they wished to withdraw two of the earlier tariff proposals and substitute a new CPP proposal they felt would garner more customer acceptance. The ALJ permitted withdrawal of the two earlier IOU proposals and the submission of these new proposals in late December, and WG2 subsequently met to consider them, and then filed its third report on

January 16, 2003. As a result, at the conclusion of Phase 1 we consider three dynamic pricing proposals: two are critical peak pricing tariffs (one presented by ACWA and the other known as the "Joint Utilities' CPP Proposal" or the "Joint Proposal," presented by the respondent IOUs), and the third is SDG&E' variation on the Joint Proposal, including the HPO tariff. We also consider two demand bidding programs, one presented jointly by the respondent IOUs and the other presented by the CPA. And finally, we consider two pilot programs: a proposal presented by IMServ known as the "Constrained T&D Capacity Proposal"[24] and an real time pricing pilot presented by Infotility.[25]

1. Dynamic Pricing Proposals

In general terms, a dynamic rate allows rates to be adjusted on short notice, typically an hour or day ahead, as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. Critical peak pricing tariffs and real time pricing tariffs contain dynamic rates.[26]

A critical peak pricing tariff includes a dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real time system conditions. In a *fixed-period* CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a *variable-*

[24] See WG2 Report dated December 13, 2002, pp. 86 – 93.

[25] See WG2 Report dated December 13, 2002, pp. 93 – 94.

[26] See *Glossary of Retail Electricity Rate Terms*, Attachment A to D.03-03-036.

period CPP, the time, duration, and day of the price increase are not predetermined.[27]

[redacted]

adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.

a. The ACWA CPP Proposal

The ACWA CPP proposal, initially presented in the November 15, 2003 WG2 Report[28] is designed to present little or no risk for customers; to be easily understood; and to be inexpensive (in terms of personnel or hardware) to implement. ACWA proposes that CPP be an option available to any IOU bundled service end-use customer who qualifies for existing rate schedules A-10, E-20, GS-2, and TOU-8. The IOU will determine the Critical Peak Periods (based upon low reserves, local transmission problems, high wholesale prices, or system peak), and will call at least 6 CPP hours each summer month. Under the ACWA

"no lose" proposition. Customers who do not respond pay no more than their current demand charges.

In its written comments, BOMA applauds the ACWA proposal as thoughtfully fleshed out, and supports it as the proposal that best protects customers. On the other hand, the respondent IOUs object to the ACWA plan because it provides significant potential bill savings to participating customers, on a no-risk basis, with no assurance of new demand reductions. This range of views highlights the chasm we must bridge.

Our goal is to develop programs that will provide meaningful demand response. Naturally these programs must be attractive to participating customers. But there is legitimate concern that ACWA's proposal provides generous bill savings to participants who provide little demand response in return, as customers need only respond during 6 critical peak hours each summer month in order to achieve a significant reduction in their demand charge. Further, if the customer's peak demand already occurs outside the 6 hours in question, the customer receives these savings in return for virtually no response. There must be a meaningful quid pro quo. Additionally, the ACWA CPP lengthens the averaging period used in determining the customer's demand charge (from a 15 minute interval to 6 hours), thus creating a revenue shortfall for all other customers. On balance these factors persuade us against adoption of the ACWA CPP proposal.

b. The Joint IOU CPP Proposals

applicable tariffs. Critical peaks will have two pricing levels, covering the seven-hour peak period. There will be a fixed number of CPP operating days (i.e., a maximum of 12 CPP days called per summer).[29] High priced CPP days will be communicated to customers on a day-ahead basis. CPP days will be selected on the basis of forecasted utility-specific weather conditions with a predetermined zone.[30]

As proposed, for usage between 3:00 and 6:00 p.m. on a CPP day, critical peak prices would be set at a level equivalent to five times the utility's specific otherwise-applicable total on-peak energy charge (that period most closely corresponding to the statewide system peak). For usage between Noon and 3:00 p.m. and between 6:00 p.m. and 7:00 p.m. on a CPP day, critical peak prices would be set at a level equivalent to three times the utility's specific otherwise-applicable total partial peak energy charge. Excess revenue amounts generated by CPP rates on program operating days will be used to discount on-peak and part-peak energy charges on non-CPP operating dates, such that rates are revenue neutral in comparison to each otherwise-applicable rate schedule on a class-average basis. Revenue neutral in this case will mean that if an average usage level customer is on this rate, and does not respond by reducing demand during the called critical peak periods, the customer will pay the same total bill, or same average rate, as if they had been on the default tariff.

As proposed, this program would not be available to those currently participating in an existing load reduction program. The customer group

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[29] In their response to the ALJ's February 21, 2003 Ruling, the IOUs submitted pro forma tariffs including this 12-day provision.

[30] See, Southern California Edison Company's Addendum to Working Group 2 Report Submitting Critical Peak Pricing Proposal, Attachment "A," p. 1.

targeted for this rate accounts for approximately 6,500 MW of aggregate commercial air conditioning load on typical summer peak days. If the program is implemented voluntarily, without transitional incentives, the IOUs project totals of 35 MW in 2003, 76 MW in 2004, and 85 MW in 2005. We discuss adoption of several transitional incentives later in this decision.

There are several critiques of the Joint Proposal. For example, on January 21, 2003, the City and County of San Francisco (CCSF) requested permission to intervene in this proceeding in order to raise issues regarding the Joint Proposal's interplay with San Francisco's unique peak electric loads. CCSF supports the Joint Proposal as consistent with CCSF's Electricity Resource Plan which seeks a 16 MW reduction in peak load by 2004. However, CCSF is concerned that the statewide Joint Proposal does not adequately capture San Francisco's peak load profile. CCSF wishes to work with PG&E to develop a pilot program to ensure that 1) the program will be applicable from May through

issues raised by CCSF have been acknowledged by the WG2 participants, where discussions have focused on how the CPP proposals might be modified to address these concerns in some meaningful fashion.[32] Rather than create a CCSF pilot program, however, we will direct PG&E to work with CCSF to create a localized marketing and recruitment area and triggering conditions for the existing CPP tariff proposal. Our decision requires PG&E and CCSF to submit an advice letter containing the details of this localized plan.

BOMA, whose constituency is the targeted audience for the CPP offering, also regards the Joint Proposal as unattractive in key respects. BOMA is concerned that its members may not have the ability to shed the significant additional load that must be shed during the CPP periods, and that the IOUs have given insufficient attention to understanding and addressing these obstacles. BOMA also believes the Joint Proposal requires further fleshing out.[33] TURN opposes adoption of the Joint Proposal, arguing that it relieves large customers from their embedded generation cost responsibilities, provides meaningless incentives, has no mathematical foundation, and is better evaluated in a traditional rate design proceeding.[34] ORA also expresses some concerns about the projected participation levels and demand response from the Joint Proposal, as well as the connection between incentives and [redacted].[35]

DGS, on the other hand, supports the Joint Proposal as a way to shave expensive, peak energy consumption.[36]

We understand the initial reluctance of large customer representatives such as BOMA to embrace CPP. We also understand why others such as DGS and the CCSF embrace the program. No one program appeals to all large users. That is why we have considered a variety of tariffs and programs in Phase 1 and will be considering others, such as two-part RTP tariffs, in Phase 2. At this particular time, however, it is important to provide at least some options to large customers and to encourage their participation in these various programs so that we can begin to meet the state's demand response goals. The CPP effort involves a relatively modest expenditure through 2004, provides customer choice, and also allows us to take advantage of the AB29X infrastructure that is already in place in order to increase demand response in the near term. For all of these reasons, we authorize the Joint Proposal, subject to certain modifications discussed subsequently in the "Customer Participation Issues" section of this decision. These modifications, relating to agricultural customer participation, multiple meter situations, multiple program participation, and the use of incentives, are designed to promote customer participation in the program.

c. SDG&E's Suggested Variations on the Joint Proposal (CPP/HPO)

SDG&E intends to maintain its previously authorized critical peak tariff (Schedule AL-TOU-CPP) while implementing a new CPP tariff based on

[36] DGS January 27, 2003 Comments on the Working Group 2 Reports, pp 2- 3.

the Joint Proposal's statewide program.[37] However as a modification to the Joint Proposal, and in the interests of capturing additional demand reduction from commercial office building complexes or business industrial parks, SDG&E recommends that the customer participation threshold be reduced from 200 kW to 20 kW. If we were to accept this recommendation, the CPP rate would be available to SDG&E's AL-TOU/EECC rate schedule, which includes all commercial accounts 20kW or greater. SDG&E has over 16,000 such accounts and plans to target about 6,700 of these for CPP participation. SDG&E projects the additional metering costs at $43,750 for 2003 and at $20,000 per year thereafter.[38]

At this time, we will not adopt SDG&E's proposal to expand this program to customers whose usage spans 20 kW to 200 kW. There is no record for doing so, or for calculating the costs of such an expanded program. Instead we will confine the CPP program to SDG&E customers whose usage exceeds 100 kW, as this Commission has previously authorized SDG&E to procure, install and operate real time meters for each of its customers (except exempted agricultural customers) with peak demand of 100 kW or more (D. 01-05-032, *mimeo* p. 6).[39] [40]

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[37] Errata to Comments of SDG&E on Working Group 2 Reports, dated January 31, 2003, p. 3.

[38] SDG&E's Supplemental Comments Responding to Data Request in February 21, 2003 Ruling, p. 3.

[39] That decision allowed the establishment of an RTEM Memorandum Account associated with the $12.5 million of purchase and installation costs for the meters and the accompanying meter data management system, while deferring the issue of actual cost recovery and cost allocation to a subsequent reasonableness review.

[40] SDG&E's customers in the 200-300 kW range do not have AB29X meters installed, so SDG&E will incur additional costs if these customers participate in the programs

Footnote continued on next page

SDG&E also wishes to convert an existing pilot program, its Hourly Pricing Option (HPO), into a full-scale program to be provided in concert with the Joint Proposal. We approved SDG&E's existing HPO in Resolution E-3782 issued August 22, 2002, so that it could launch an hourly metering and pricing pilot program during the summer of 2002 to test customer acceptance, demand response, behind-the-meter energy management technologies, and billing processes associated with dynamic retail energy commodity pricing. This HPO for commercial customers was to use interval meters, and charge varying on-peak hourly rates to customers based on next-day demand forecasts. The utility was to provide participating customers with hourly commodity price information on a day-ahead basis through the Internet, allowing them to adjust their usage accordingly. As approved, the HPO was to be offered to no more than 35 commercial and industrial customers with demands of 20 kW or greater on a first-come, first-served basis. However, in anticipation of decisions to be issued in this docket, SDG&E has not been aggressively promoting the HPO tariff to customers and, as of January 31, 2003, it had not signed up any customers for this program.[41] Instead, SDG&E proposes to convert the HPO into a full-scale program and modify it by expanding the hourly prices to semi-peak periods, on the rationale that customers will have greater flexibility to reduce costs by shifting or reducing load from the higher on-peak hourly periods to the semi-peak "shoulder" periods.[42]

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authorized in this decision. However this Commission has already authorized SDG&E to procure real time meters for customers with usage exceeding 100 kW (D.01-05-032).

[41] SDG&E's February 1, 2003 Program Evaluation Report #1, "Hourly Pricing Option Pilot, Schedule EECC-HPO," p. 6. As required by Resolution E-3782, SDG&E served this report on the service list of R.02-06-001.

[42] SDG&E's January 27, 2003 Comments on the WG2 Reports, pp. 5 –6.

The CPP tariff proposed jointly by the respondent IOUs would create a tariff with two high on-peak rates in critical situations, but leave prices in the shoulder and off-peak periods averaged as in normal TOU tariffs. Since the SDG&E proposal expands the number of hours for which hourly rates are revealed to the participant, and thus breaks new ground, we will adopt it, making the HPO a full-scale program for SDG&E and as part of that, extending its hourly pricing features to cover shoulder hours. Consistent with the customer participation levels authorized for the CPP tariff, we will permit SDG&E to offer the HPO tariff to all customers with monthly demands >100 kW. However for the time being, we will confine this outcome to SDG&E, and not impose it upon PG&E or Edison. There is a simple reason for this: while WG 2 is in the early stages of exploring the development of a two part tariff suitable for mid-

a. IOU Demand Bidding Program

This Commission requires that demand response [redacted]

included in each utility's long-term resource plan[43], a decision made after this rulemaking was underway, and thus causing some retooling of the IOUs' Phase 1 demand bidding proposal. The IOUs presented their original joint proposal in the November 15, 2002 WG2 report, and subsequently modified it.[44]

The IOUs initially proposed that a common statewide market-based DBP program (requiring a price trigger) be developed after the ISO's day-ahead market has been established, as projected in Spring 2004.[45] However they now believe there is no reason to wait. The IOUs have always favored the continuation of the existing Commission-authorized reliability-based demand bidding program. However they now propose the expansion of available demand bidding options, allowing participants to reduce demand voluntarily when requested by the IOUs in one of two ways: via 1) a price trigger and 2) a system emergency trigger.

Under their current market-based DBP proposal, IOU procurement departments will use current information and historical trends to forecast an hourly "price offer" on a day-ahead basis. This is a form of utility-specific

PM and the program is triggered when the price offer is $0.15 per kWh or greater.

While a recurrence of year 2000 resource scenarios may be unlikely in the near term, the IOUs believe there is value in understanding the price responsiveness of customers during emergency situations. To that end, they propose that artificial conditions periodically be put in place to obtain this data, and for this purpose they would test the DBP at "emergency incentive" levels up to twice per year, four hours total. This emergency trigger, meant to simulate a CAISO "Alert" or "Warning" notification (when system reserves are forecast to be 7% or less between Noon and 8 PM weekdays only), would serve not only as an incentive to the customer to join the program, but would also determine the extent of participant response. A customer must submit a "committed load reduction" bid, and will receive $.50 per kWh of demand reduced during a test event. For purposes of payment, minimum (50%) and maximum (150%) load

In order to determine performance, the IOUs will use a new variant of a customer specific 10-day rolling average energy usage baseline. There was some concern that the current methodology does not scale baseline to actual demand, and BOMA argued that it may be unfair to customers with weather-sensitive loads. The IOUs responded by proposing a new method of calculating the 10-day rolling average, "using the average of energy usage for the three highest days for the same hour during the past ten similar days prior to a DBP event."[46] They assert that this new method tends to reduce any negative bias that

used absent the program, and avoids the gaming opportunities provided by adjustment mechanisms that scale baselines based on usage just prior to a DBP event.[47] On balance, the revision to the baseline methodology proposed in the March 11 WG2 Report appears to address concerns about the fairness of the

[redacted]

rolling 10 day baseline calculation, and we will make no further modification to the baseline calculation in this decision.

The IOUs propose to make their demand bidding program available to individual commercial/industrial bundled service customers not otherwise on an RTP base rate, or Agricultural rate schedules, whose usage is 200 kW or above, and who have interval meters capable of recording metered data on a 15 minute interval. The IOUs propose to offer such interval meters to the customers at the utility's expense if such metering is not already available on site. Customers must take service under the provisions of their otherwise applicable rate schedule. Participating customers must commit to reduce load by at least 100 kW during a DBP event and agree to reduce their load by their committed load reduction amount in the event of an emergency DBP event. Under the proposal, there would be no aggregation of customer accounts or their associated loads.

Besides these operational modifications to the existing demand response program, the IOUs propose to offer a transitional technical incentive package to DBP participants. This incentive package is the same as that offered to CPP participants, as discussed subsequently in this decision.

We agree that there is no reason to wait for the CAISO to develop a day-ahead market in order to implement the DBP [illegible] IOUs

Bidding Program, as presented in the March 11, 2003 WG2 Report[48], subject to certain modifications. First, we do not accept the limitation proffered by the IOUs that the DBP be available only to those not on another dynamic pricing tariff. In addressing multiple participation issues subsequently in this decision, we specify certain circumstances under which customers may participate in both the CPP and the IOU DBP. Second, we will allow some participation of multiple meters at a single site, under guidelines detailed subsequently in this decision.

Third, we see no reason to exclude from the DBP certain agricultural customers whose usage exceeds 200 kW and who have interval meters in place. Since agricultural customers are currently participating in the IOUs' reliability-based demand response programs,[49] there can be no argument that their participation is infeasible, or that their participation, as limited above, increases costs to other ratepayers. To our knowledge no specific argument against their participation in the proposed statewide program has been made. Therefore, this order allows certain agricultural customers to participate in the adopted Joint Utility Demand Bidding Program.

b. The CPA Demand Reserves Program

In the interests of coordinating an existing program with the IOU proposals being developed in this proceeding, WG2 also assessed how the CPA's existing Demand Reserves Partnership (DRP) could be used to meet our demand response goals. The design of the CPA DRP is governed by a contract between CPA and the Department of Water Resources (DWR). In D.02-10-062 we directed the IOUs to include the available resources from the CPA DRP in their long-term

[48] Exclusive of the incentive features whose merits are addressed subsequently.

[49] SCE's Agriculture and Pumping Interruptible Program and TOU-PA-SOP-I tariff.

procurement plans. In D.03-02-031 we approved $29 million in CPA DRP costs for inclusion in the 2003 DWR revenue requirement. In this decision, we determine how this program will assist in meeting our stated demand response goals. In that regard, one of its primary benefits is its availability to a much broader array of participants than the IOUs' DBP; any end user (bundled or direct access) of the IOUs, as well as end users of cooperating load serving entities in California may participate in the CPA DRP.

Under this program the CPA uses load reduction by end users to provide demand reserves in the wholesale market. These demand reserves can be used in two ways: 1) Ancillary Services –as ten minute response non-spinning reserves or sixty minute response replacement reserves in the ISO markets; and 2) Call Option – as energy supplied in the ISO day ahead, hour ahead or supplementary energy markets during high wholesale market price or critical demand times. CPA contracts with demand reserve providers to work with end users and be contractually responsible for delivering the load reduction when called. Demand reduction for individual end users is limited to 11 AM to 7 PM, Monday to Friday for 24 hours per month, or 150 hours per year. Two different types of baselines are used to compute load reduction, one for those participating in the Ancillary Services of Supplemental Energy Markets, and the other for Call Options delivered into the ISO day ahead or hour ahead markets.[50]

At present, each IOU will receive credit towards the demand response goals set in this proceeding for any CPA DRP resources that it schedules. And in the absence of further direction from the Commission, it is likely that each IOU will schedule with the CAISO those CPA DRP resources that are inside or closest to its retail service area. However we will direct the IOUs to

[50] See Working Group 2 Report dated January 16, 2003, pp. 18 – 22.

work with the CPA and DWR to develop and file, within 120 days, a mutually acceptable alternative mechanism for allocating these resources in 2004, unless such an alternative mechanism is developed in the procurement proceeding (R. 01-10-024). This timetable is designed to allow resolution of the issue by the Commission prior to the start of 2004.

While D. 02-10-062 requires the inclusion of DRP resources in the IOUs' long-term procurement plans, it is evident that the IOUs need to coordinate their scheduling activities with the CPA more closely in order to ensure that the DRP resources are actually dispatched when it is cost effective to do so. The IOUs must coordinate their customer, meter, scheduling and settlement activities in a manner that maximizes the full potential of the CPA

operating in parallel, should be available. This means that in the near term the IOUs will be able to dispatch from either one.

3. Pilot Programs

a. The T&D Peak Capacity Proposal

The T&D Peak capacity proposal is presented by IMServ whose products and services include collecting and providing advanced energy information, including settlement services to utilities and energy service providers, among others, and providing metering services. The proposal is rooted in the concept that customers should receive financial benefits in the form of reduced transmission and distribution (T&D) charges when they take actions that provide benefits on constrained T&D systems, thereby ameliorating adverse impacts associated with T&D upgrades and the environmental impacts of running peaking units in transmission constrained areas. This proposal targets electric customers (both direct access and bundled) above and below 200 kW in T&D constrained areas.

IMServ proposes that this program be implemented via the CPA's Transmission Pilot Program. The utilities would be required to identify constrained T&D areas as well as cost effective incentives for reducing these constraints. Finally the program must be marketed and customer T&D reductions calculated. Proof of concept operation of the pilot would occur during summer 2003, and the program would be expanded during summer 2004.

In D. 03-03-036, we considered and rejected this program for small commercial customers because it lacked the specificity necessary for implementation in Phase 1. The result is no different here. The pilot description is simply too general and the specific concepts to be piloted are missing. By summer 2003 it is simply impossible to develop hourly prices for transmission and distribution constraint costs and to use such prices as inputs to a demand

response program. Therefore we will not approve the IMServ proposal in this decision.

b. The Infotility Proposal

During the WG2 process, Infotility presented a draft real time pricing proposal which stimulated discussion, and caused the WG2 participants to recommend that testing alternative design features of a two part RTP tariff might prove useful.[51] The Infotility proposal is designed to test or identify 1) customer interest and response to a real time price signal across multiple building types; 2) customer preferences for baseline methodologies; 3) specific customer education requirements prior to participation in a two-part RTP tariff; 4) technical and administrative barriers to a full roll out; 5) customer satisfaction; and 6) "lessons learned."

Under the pilot proposal, participants remain on their existing tariff schedules and are billed for actual usage. They are debited/credited at a second rate (the market price) for the difference between actual usage and their baseline usage. Baselines are negotiated and may be adjusted monthly or on a day ahead basis. At the end of each month, customers receive a statement summarizing their performance relative to the baseline method employed under the program. If there is a net positive balance, customers earn an incentive credit; if there is a net negative balance, the customer is charged a debit. At the end of the program the customer is eligible to receive an incentive payment equal to the positive balance at the end of the program. If there is a negative balance the participating customer receives nothing.

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[51] WG2 Report dated December 13, 2002, pp. 93-94. See also Appendix C to the December 13th report.

whose members have expressed interest in a two-part RTP tariff in the past. These include the Silicon Valley Manufacturing Group, OBMC program participants excluded from demand response programs, CMTA, BOMA, and

Commission should order the IOUs to install interval meters (and meter data communication) on all 200 kW and above meters and allow the cost of these installations as authorized additions to plant for ratemaking purposes.

On February 21, 2003, the ALJ issued a ruling requesting information from the IOUs about the estimated costs of installing AB29X advanced metering systems that would enable agricultural customers to participate in demand response tariffs or programs. Edison reported that agricultural customers were included in its AB29X RTEM program and that no additional funding is necessary other than that requested in its current GRC filing.[54] SDG&E reported that its AB29X implementation plan includes installation of such meters for its agricultural customers with demands >300 kW;[55] for its 461 agricultural customers with demands <200 kW, SDG&E estimates that no more than 10 sites per year would participate in the CPP, and that estimated annual metering costs would not exceed $20,000 for these customers;[56] for its 36 agricultural customers with demands between 200 kW and 300 kW, SDG&E estimates initial costs of $63,000, and ongoing annual costs of $10,000.[57] PG&E reports that it currently has 908 agricultural customers with demands >200 kW. Of these, 251 already have real time meters, and 657 have kWh or time of use meters. PG&E provides a range of one-time meter

[54] Edison Response to ALJ's February 21, 2003 Ruling, p. 4.

[55] SDG&E Response to ALJ's February 21, 2003 Ruling, p.2

[56] SDG&E Supplemental Response to ALJ's February 21, 2003 Ruling, p. 2.

[57] SDG&E Response to ALJ's February 21, 2003 Ruling, p. 2.

installation costs ($854,000 to $1.6 million, depending upon telecommunications options) for these 657 customers.[58]

Based on the IOUs' responses to the ALJ's February 21st ruling, it appears that the major cost issue relative to agricultural customer participation, is posed by PG&E's 657 customers who lack interval meters. Based on the figures presented, the cost implications for Edison and SDG&E appear to be less significant than the PG&E situation. While we wish to maximize the participation of all customers, including agricultural customers, in the demand response programs authorized in this decision, the record is not well developed on the issue of agricultural customer participation. We must carefully consider the participation of agricultural customers to determine which rate schedules are likely to provide meaningful, cost-effective demand response within the structure of the programs adopted in this decision. This we will do in Phase 2 of this proceeding. In order to allow some agricultural participation now, at the 200 kW level and above, we will authorize participation by agricultural customers on certain specific rate schedules, as proposed by PG&E and SDG&E. For PG&E, these are customers on options C and F of the AG-4 and AG-5 rate schedules, who have an existing interval meter. For SDG&E, eligible customers must be on schedule PA-T-1. Edison has not proposed specific tariff schedules, but rather proposes to transfer participating agricultural customers to discrete commercial accounts. We do not adopt this proposal, but instead will require Edison to identify specific tariff schedules eligible for participation. The 200 kW threshold, rather than the 100 kW threshold approved in D.01-05-032, applies to SDG&E as well, since the authorization provided in that decision excluded agricultural customers. So that additional agricultural customers who do not currently have

[58] PG&E Response to ALJ's February 21, 2003 Ruling, pp. 5 –6.

interval meters are able to participate in these programs in the future, we will review the cost implications of such participation in Phase 2 of this proceeding.

[redacted]

2. Multiple Meter Situations

WG2 explored, but did not resolve, the issue of participation by customers at multiple meter facilities, where no single meter is >200 kW, but in aggregate the total usage at the customer's facility exceeds 200 kW. The IOUs apparently implemented their RTP metering contracts with the CEC differently, so some of these customers may have interval meters while others do not. While we understand that a liberal aggregation policy will encourage more customer participation, that goal must be balanced against the unknown metering costs and the paucity of our present knowledge about small commercial customer demand response. Thus, we do not allow aggregation at this point, but we are open to exploring this issue further in Phase 2 of this proceeding.

We will, however, allow customers with multiple meters at one site where at least one meter already exceeds 200 kW, to combine other smaller meter loads at the same facility for purposes of participation in the tariffs or programs authorized in this decision. In the interests of clarity, we will adopt a proposal made by PG&E in its comments to define permissible multi-meter participation.

An eligible site must be defined under the IOU's appropriate tariff rules (e.g., Rule 1 for PG&E) or consist of adjacent customer premises.

3. Multiple Program Participation

The participation of customers in multiple programs presents challenging issues. From the customer perspective, participating in a specific program requires hardware investments and management attention that can be

response from one program will affect the "baseline" of another program. From the system operator perspective, it may be difficult to credit loads participating in multiple programs unless it is very clear how this affects aggregate capacity and the incremental capacity remaining once the system conditions leading to a sequential call of programs has been initiated.

From our experience with traditional interruptible tariffs and load curtailment programs, the specific concerns have focused on two key concerns: the possibility that customers will be compensated multiple times for the same load response (so-called "double dipping"), and the possibility that potential load relief associated with a particular program will be "double counted." Double counting occurs when the participating load on one program is the same load that is expected to perform in another program at the same time. Concerns have also been raised that multiple participation can add layers of billing and administrative costs associated with "overseeing" participation and calculating complex settlements. And utilities are concerned that such overlapping program participation may inhibit enrollment and cause customer dissatisfaction and confusion.[59]

On balance, however, we believe that multiple participation should be allowed provided that there are acceptable guidelines governing its applicability to the programs adopted in this decision. At this point in time, we will test multiple participation scenarios against the goal of avoiding both double dipping and double counting, as defined above. To develop this issue further in our rulemaking proceeding, the ALJ requested parties' comments on four multiple participation scenarios, some of which we will adopt. As we gain more

[59] See, e.g., Edison comments to February 21, 2003 ALJ Ruling, p. 6; and SDG&E Comments to February 21, 2003 ALJ Ruling, p. 4.

experience with the interaction of these programs over time, we will be open to considering the adoption of additional scenarios.

a. CPP and CPA DRP (or IOU DBP)

May a bundled service customer on CPP also participate in the CPA DRP (or the IOUs' DBP) during hours when CPP prices are in effect, as long as the customer does not receive energy payments (from the CPA or the IOUs)? The answer is "yes," subject to certain conditions. This approach will balance providing an incentive to encourage customer participation and not making two energy payments for the same load reduction.

While the IOUs oppose this scenario as unlikely to provide additional load reduction because DRP and CPP operating days must be the same (PG&E Comments to ALJ's February 21st Ruling, p. 7), we note that the CPP will be in effect for only 15 days per summer, whereas the DRP can be in effect 150 hours a year. Thus, CPP customers should be allowed to participate in the IOU DBP and CPA DRP, but not receive energy payments during CPP-event hours. The CPA offered to account for and monitor the multiple program ramifications of the CPA DRP in the January 16 WG2 report and we will request that they do so.[60]

b. OBMC/CPA DRP

May a customer on an OBMC rate also participate in the CPA DRP, as long as the customer does not receive energy payments from the CPA during hours when the OBMC curtailment is in effect? Here, the answer is "Yes."

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[60] WG2 Report dated March 11, 2003, p. 26: "CPA will insure that no [energy] payment was made during hours that the utility program curtailment events were being exercised."

PG&E asserts that this form of multiple participation makes it almost impossible to predict the expected load reduction when an OBMC event is called and thus can have serious ramifications in forecasting load drops during a rotating outage. While this may be true, the load reductions offered by the CPA DRP are considerably cheaper per MW than those load drops available during an emergency through OBMC. In addition, load participation in the DRP may help avoid the need to call an OBMC event. On its face, this proposed multiple participation also does not raise a double dipping or a double counting concern, because of the non-payment periods for the DRP program during an OBMC event. Thus, we will allow customers to participate in both the OBMC tariff and the CPA DRP.

c. A customer on interruptible rates who places additional load, below its firm service level, on the CPA DRP and receives reservation payments.

The IOUs recommend against this combination, but we will allow it. PG&E argues that most interruptible rate program participants have already specified relatively minimal firm service levels, so that additional load that might be made available for the CPA DRP under this approach would not be significant.[61] As events unfold, that may be the case, but it is not entirely clear now. What is clear is that if an interruptible rate program participant wanted to participate in the CPA DRP, the customer will receive a reservation payment for additional load below the firm service level designated by participation in interruptible tariffs. Theoretically, while both load segments would receive capacity payments, each segment represents "new" load and each would receive

[61] PG&E Rersponse to ALJ's February 21, 2003 Ruling, p. 8.

separate payments. There is no dual compensation. Therefore we will allow this combination.

d. May a customer on existing interruptible rates have existing curtailable load participate in the CPA DRP spot market options, assuming that no payments are made during the hours of curtailment due to the interruptible rate?

The answer is "yes," in part. Interruptible rate customers should be able to participate in the CPA's Supplemental Energy Markets, since no capacity payment if offered and no energy payments are made during interruptible program load curtailment events, as this scenario is described. Thus double compensation cannot occur under this scenario. Where interruptible customers already receive a capacity payment for participating load, they should not be allowed to participate in the Ancillary Service option (where a capacity payment is offered), as this would constitute double compensation.

4. Transitional Incentives

In its final report issued March 11, 2003, WG2 asserts that additional incentives are required to clear some significant hurdles that may impede our demand response goals. These hurdles include significant customer inexperience with demand response programs, customer reluctance to make the expenditure of time and effort necessary to participate in these programs effectively, as well as the perceived risk of participation. Representatives of one targeted group, BOMA, doubt that their constituencies will participate in the programs, as described in previous WG2 reports. And the IOUs report low levels of participation in existing demand bid programs, thus indicating that program changes, incentives, and more robust marketing may be needed to ensure broader participation. As a result WG2 proposes two basic transitional

incentive options both of which would apply to the CPP Joint Proposal and SDG&E's HPO tariff, and one of which would apply to the IOUs' Demand Bidding Program.

These transitional incentives share common objectives: to increase initial customer participation levels, achieve significant demand response, provide the foundation for demand response programs, allow for experimentation with demand response capabilities, and accelerate the installation and use of demand response capabilities (March 11, 2003 WG2 Report, pp. 9 – 10).

a. CPP/HPO Incentive Proposal

For customers participating in the CPP and HPO programs, WG2 proposes that two types of transitional incentives be available, and that participants be allowed to receive one or both, either simultaneously or sequentially.

Under the proposed "rate protection incentive," the goal is to provide 100% bill protection, meaning that the participating customer pays no more than they would had they remained on their original rate schedule. Such customers are so protected for the first 12 months they are on the program, but no later than December 31, 2005. After the initial 12 months, if the sum of the CPP or HPO bills is higher than the sum of the bills on the otherwise applicable rate schedule, participants will receive the differential as a bill credit. There is no bill protection for individual customers after their initial 12 months on the program, or after December 31, 2005. BOMA maintains that the 100% bill protection feature should extend for the life of the CPP and HPO programs, and not just for 12 months, so as to allow customers to take the time necessary to adjust and adapt to the HPO/CPP regime.

Participation is capped at 500 MW (200 MW for PG&E; 200 MW for Edison; and 100 MW for SDG&E). The rate protection option is nearly no cost as long as existing revenue requirements are established and shortfalls are collected through appropriate balancing mechanisms.

To receive the benefit of the CPP, customers under the bill protection option must actually reduce peak demand by a minimum of 3% per CPP event averaged over the course of their 12 months' participation. If this minimal load shifting does not occur, the customer will not be given a CPP credit for participation under the program. Instead, the customer will only receive a refund to the extent its CPP bill exceeded the charges under its otherwise applicable tariff. The customer must also agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program. Finally, since the CPP is a voluntary tariff, a customer may leave at the end of the 12-month period during which they received 100% bill protection, but a customer who leaves before the 12-month commitment ends will not receive bill protection.

In the case of the HPO tariff, the WG2 reports are silent as to how the 3% performance requirement is to be met. HPO customers receive their pricing signals daily; therefore they cannot be expected to meet a 3% demand reduction requirement daily and we do not believe this is what is contemplated by WG2. Rather, a 3% reduction could be averaged over the entire time period of the customer's participation in the HPO (or annually, as applicable). In its tariff filing, SDG&E should specify the exact nature of the performance requirement for HPO customers.

BOMA is indifferent to the 3% performance obligation, but it does believe that a customer should receive the full bill protection if it remains on the CPP tariff through one of its four month summer cycles, as opposed to the full 12

month period. Edison is concerned about the complexities of implementing the 3% performance obligation and believes that offering bill protection for 12 months without the complex measurement obligation would encourage maximum participation in the most cost effective way.

Under the proposed technology incentive, a CPP or HPO participant

[redacted]

that enhances the customer's ability to respond to curtailment events. Technology such as, but not limited to, automated load control hardware, energy management systems, and smart thermostats may be eligible for this transitional incentive. Professional technical advice solicited and received by the customer that leads to actual demand response may also be eligible for a rebate. One WG2

remainder of the incentive will be paid after the customer has achieved certain milestones. More specifically, to receive the 50% rebate remainder, the customer must show a calculated peak demand reduction equal to at least 50% of their estimated load drop per CPP event, as averaged over 4 consecutive CPP or HPO months, while on the program and before December 31, 2005. If this minimum level of measured load shifting does not occur, the customer would not be given

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the 50% rebate remainder. BOMA is concerned that imposing a performance requirement as a condition for reimbursement will cause many customers to forego these programs, and suggests that some level of technical assistance be offered to customers free of charge.

To determine performance, kW drop is estimated as the difference between the customer's specific baseline for that hour (calculated via a 10 day rolling baseline) and the customers actual energy usage during that hour. Edison is concerned that the 10-day rolling baseline is a measurement not used in any form in the tariff, and thus would complicate billing operations. It proposes a compliance measure it considers much simpler: reduction in historical on-peak usage measured annually. BOMA is concerned about the manner in which the estimated load drops are set. It believes that individual customer input is necessary and it is concerned that weather and temperature conditions must be taken into account in a manner that does not disadvantage participating customers.

Funding for the CPP/HPO technical incentive option is proposed at $11.375 million for all three IOUs (the incentive costs totaling $10 million,

remaining dollars from any category can be used to keep the entire program going.[63]

b. Demand Bidding Program Incentive Proposal

The IOUs propose to offer a transitional technical incentive package to DBP participants, identical to the transitional technical incentive package offered to CPP/HPO participants. They will offer no bill protection incentive to these customers.

Funding for this DBP technical incentive option is proposed at $8.249 million for all three IOUs (the incentive costs totaling $5.375 million, emergency tests totaling $2.124 million, and program tracking costs totaling $750,000).[64]

CLECA questions whether there is sufficient evidence that technical incentives will motivate customers to participate in the DBP program, as DBP involves determining the load to be bid into the market and the price, in contrast to simply reducing load in response to a price signal.

For its part, CUE questions the cost of the technology incentives (for CPP and HPO, not just DBP), arguing that the Commission should not authorize such costs for ill-defined qualifying equipment until it has determined whether the free advanced meters already installed by the State will be an adequate "incentive" to meet demand response goals. CUE is concerned that WG2 exceeds its mission of developing tariffs that enable large customers to expand their demand response capabilities.

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[63] Working Group 2 Report dated March 11, 2003, p. 16.

[64] Working Group 2 Report dated March 11, 2003, p. 24.

While supporting the objectives of the transitional incentives for all three programs, ORA believes that better and more effective incentives may be provided through the redesign of current TOU rates and changing the CPP rate design to increase the discount level so it would be equivalent to the interruptible and other demand response programs.

c. Adopted Transitional Incentives

For the CPP and HPO programs we will approve the bill protection incentive. Despite BOMA's argument that the program should extend well beyond 12 months for participating customers, we will authorize only a limited extension of the program, to 14 months. We do this because the CPP tariff may not be available until later this summer, and we are concerned that CPP events will be called in the Fall of 2004. This modest extension will provide meaningful protection during these additional events. We will also adopt the proposed 3% performance obligation, although we understand Edison's argument that a less rigorous performance obligation would be somewhat easier to implement. On balance, however, we prefer to have a more precise demand reduction measurement. To receive the benefit of the CPP, the customer under the bill protection option must actually reduce peak demand by a minimum of 3% over the course of their 14 months' participation. Bill protection will be credited at the end of the 14-month period of successful participation. If this minimal load shifting does not occur, the customer will not be given a CPP credit for participation under the bill protection program. Instead, the customer will only receive a refund to the extent its bill exceeded the charges under its otherwise applicable tariff.

We will also adopt two other proposed performance obligations: the site visit and survey completion agreement, and the time commitment as a condition for receipt of bill protection. We will also cap the bill protection

program at 500 MW as proposed, while noting that this incentive does not increase costs.

We decline to approve the technical equipment portion of the technology incentive for either the CPP/HPO or DBP. While an equipment-based rebate is potentially helpful in augmenting demand response based on the projections included in the March 11th WG 3 Report (Table 2), the proposal lacks key detail, including a method for determining what constitutes "qualifying technology." More significantly, the level of projected costs exceeds $11 million, a significant amount, with no indication of how much demand response such expenditure may encourage, a fact not counterbalanced by the inclusion of a performance requirement that would withhold 50% of the incentive in cases of nonperformance. Considering all of these factors, we will not approve the technology equipment component of the proposed technology incentive for any of the three programs in question.

We will, however, approve the technical assistance portion of the proposed incentive package, allowing a rebate for professional technical advice regarding installation of new equipment or modification of existing equipment or behavior because the modest expenditure we authorize[65] in that regard may indeed spur customer participation at a more acceptable cost. As originally proposed, a rebate of up to $150 per kW of curtailable on-peak load would be allowed for the combination of costs associated with receiving technical advice and installing technical equipment. Since we are not approving the technical equipment installation component, we will exercise our discretion and reduce the rebate accordingly. The authorized rebate amount for technical assistance

[65] As shown in the Attachment A, the total amount of these incentives for 2003 and 2004 is $3.41 million, versus the $11.3 million proposed by WG2.

will be $50 per kW of curtailable on-peak load for the costs associated with receiving technical assistance (related to the installation of new equipment or the modification of existing equipment or behavior) that leads to actual demand response. As with the original proposal, the customer will receive a transitional incentive equal to 50% of the potential payment upon certification of potential on-peak load reductions. The remainder of the incentive (the 50% remainder) will be paid after the customer has shown a calculated peak demand reduction equal to at least 50% of their estimated load drop per CPP event, as averaged over 4 consecutive CPP or HPO months, while on the program and before December 31, 2005. If this minimum level of measured load shifting does not occur, the customer will not receive the 50% remainder payment. To determine performance, the kW drop will be determined using the customer baseline proposed in the March 11th WG2 report.[66]

Our decision allows CPP/HPO customers to opt to receive just the bill protection incentive or both the bill protection incentive and the professional technical assistance incentive. Participants in the IOU DBP tariff may receive

Finally we note that the approved incentives are available to participants until December 31, 2005, or until funding under specified caps is exhausted. However if one category of funding is exhausted, any remaining dollars from any other category can be used to keep the entire incentive program running, with the caveat that at least 50% of the funding for technical assistance shall be guaranteed for the CPP.

F. Expected Impacts

We have taken several steps in this decision to augment customer participation in order to increase the amount of demand response generated by the adopted tariffs and programs. These include opening the tariffs and programs to agricultural customers, allowing certain multiple meter situations, allowing multiple program participations, as defined, and approving bill protection and professional technology assistance incentives on a transitional basis. As a result, it is expected that in calendar years 2003 and 2004, these demand response programs will provide approximately 411 MW and 954 MW, respectively (see Appendix B). While our decision to reject the technology portion of the transitional incentive proposal may diminish, to some degree, the expected MW contribution provided in Appendix B related to the statewide CPP, the HPO, and the IOUs' DBP, other steps taken to open these programs to agricultural customers and to authorize certain multiple-meter situations, and to allow discrete multiple program participation may offset any MW reduction.

G. Program Duration

The recent history of demand response programs in California is one of constant flux in program design. The WG2 participants strongly recommend that we embrace the concept of program stability, which is characterized as a policy allowing for consistent program design, eligibility and triggering mechanisms over multiple years. We are in total agreement with the WG2

participants on this point, and this rulemaking has exemplified this principle.

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ad hoc program development. In our view, program stability will help us to achieve significant participation in demand response programs. To that end, the programs authorized in this decision are designed to continue beyond calendar year 2004, and have no expiration date, although funding is authorized in this decision through calendar year 2004. We will direct the IOUs to file evaluations for all authorized programs in this decision, as well as those authorized in

The single participant will be encouraged and assisted to fit into another program.

I. Program Costs and Related Cost Issues

The cost figures for calendar years 2003 and 2004 for the programs approved in this decision, and discussed below, appear in Attachment "A" to this decision.

1. Cost-Effectiveness

We now address the question whether the four programs adopted in this decision are cost effective. California regulatory agencies have a long history of attempting to ensure that demand-side management (DSM) activities are cost effective. This Commission, in conjunction with the CEC, has established and periodically updated the Standard Practice Manual to create greater uniformity in assessments.[67] We have typically required that DSM programs be shown to be cost-effective according to one or more of the standardized tests.

The WG2 reports document the difficulties that participants have had in developing the inputs for and applying the current SPM tests to tariffs and programs that are designed to interact with markets.[68] The ALJ Ruling dated October 2, 2002 recognized some of the concerns of WG2 participants. In directing parties to proceed nonetheless, the ALJ Ruling dated November 13, 2002 provided high and low values for avoided cost scenarios to be used in the analysis.

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[67] CPUC, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," October 2001.

[68] See "Issues for Cost-Effectiveness Analyses" on page 53 of the January 16, 2003 Working Group 2 report.

The Working Group 1 principals have expressed a belief that a long-term, sustainable direction was desirable for Demand Response options in this Proceeding. We concur that a focus on the cost of a new peaker power plant[69] is the most relevant standard in determining cost-effectiveness for tariffs and programs designed to be part of a growing reliance upon demand response, just as it has been for rate design and demand side management measure evaluation historically.

The Benefit-Cost ratios of the four options being pursued are reported in Table 2. Three of the tests from the SPM were applied to the program options – the Total Resource Cost (TRC) test, the Participant test, and the Ratepayer Impact Measure (RIM) test. The TRC test considers the Benefits and Costs from society's or the total state of California's perspective. In contrast, the RIM test considers the revenue impact on ratepayers not participating on the tariff or program.

Table 2: Benefit-Cost Ratios of DR Options Compared to a New Peaker[70]

Program/Tariff	TRC	Particip.	RIM
IOU Critical Peak Pricing	15.4	4.8	1.2
SDG&E Hourly Pricing Option	14.7	2.6	0.8
IOU Demand Bidding Program	22.6	1.3	4.6
CPA Demand Reserve Partnership	2.2	3.1	1.2

[69] ALJ Ruling, November 13, 2002. The cost of a new peaker was $85/kW-yr and $.035/kWh.

[70] The IOU numbers include technical incentives and bill guarantees and are taken from the March 11, 2003 report of Working Group 2. The CPA numbers are taken from the January 16, 2003 report of Working Group 2 since no new incentives are proposed for the CPA programs. Moreover, the CPA numbers reported here are a weighted (by MW) average of the 3 CPA options reported in the January 16 report.

All programs passed all three tests, with the exception of SDG&E's HPO, which did not pass the RIM test. However, some argued that the RIM test is not directly applicable because presumably the HPO better reflects what the true costs of power are than conventional time-of-use rates – and hence participants now joining the HPO are currently subsidizing other customers on the less precise time-of-use rates. Therefore, given the limitations of the tests, all program proposals were judged to be attractive compared to investing in a new peaker of comparable MW size. Under revenue neutrality principles, discussed subsequently, the IOUs will not lose money. Further, since it has become clear that at least an initial rationale for these programs is to develop experience in attracting customers to participate and evaluating their load response when programs are triggered, we believe that these specific tariffs and programs are sufficiently cost-effective to be authorized.

We believe that the concerns expressed by WG2 participants about the validity of the SPM tests, and the process for developing inputs that accurately reflect the value of displaced supply side power procurement costs, are sufficiently important that we will direct parties in Phase 2 of this proceeding to develop and bring forward proposed modifications to the SPM.

2. The Principle of Revenue Neutrality and Recovery of Revenue Shortfalls

There is general agreement that customer participation in demand response tariffs and programs will cause the IOUs to lose revenue (compared to authorized revenue requirement) because load reduction involves both a reduction in energy usage and a shift from energy use during peak periods in which existing rate designs accentuate revenue recovery. The exact amount of revenue loss depends upon many factors, including the nature and extent of customer participation in demand response programs and other unknowns such

as offsetting energy purchase cost reductions attributable to effective demand response. In that light, the estimated dollar impacts provided at the end of the WG2 process ($11.5 million in 2003 and $29.9 million in 2004[71]) must be viewed as very conservative approximations, since they assume no short-term commodity procurement cost savings associated with these revenue reductions. Those cost savings certainly will exist, though their magnitude cannot be predicted in advance.

Under the concept of revenue neutrality proffered by the WG2 participants, the IOUs' authorized revenues should be protected from the effects of the actual demand reductions that occur due to demand response.[72] The IOUs recommend recovery of revenue shortfalls from the entire system, asserting that it is burdensome to track such shortfalls by class.

Against this recommendation, ORA argues that such revenue shortfalls should be recovered from the large customer class, not system-wide. Under ORA's proposal, certain revenue shortfalls would be recovered from the non-CPP participants in the same sub-customer class, which will give non-participating (static rate) customers an incentive to switch to CPP or other dynamic tariffs and programs. This proposal is possible due to the likelihood that some customers who volunteer for the CPP pay less under their new tariff without making any change in their usage. This happens because current static rates are designed based on average load profiles, and these customers are currently paying more than their fair share through an intra-class subsidy to users with peak loads greater than the average load. ORA proposes that this

[71] See WG2 Report dated March 11, 2003, Table 5, p. 48. WG1 staff has extrapolated from Table 5 to arrive at these approximate figures for Year 2003 and Year 2004.

[72] See WG2 Report, dated November 15, 2002, p. 29.

structural revenue shortfall (the intra-class subsidy to users with peak loads greater than the average load) be recovered from customers who choose to stay on the default TOU rate. In ORA's view, this will cause an increase in the default TOU rates, thereby encouraging more customers to migrate to the CPP tariff. ORA notes that the "dynamic revenue shortfall," the bill savings resulting from customers changing their loads in response to new prices, is offset by comparable

reductions in procurement costs, and ideally net procurement cost savings will be passed through to the cub-class of CPP participants via rate design in the form of lower off-peak prices. ORA believes that CPP rates should be designed so that the dynamic shortfall equals the avoided procurement costs.[73]

We find merit in ORA's proposal designed to encourage program participation by sending appropriate price signals. Effectively, it would cause CPP participants to receive the benefit of the full amount of avoided procurement costs, thus making the CPP rate more attractive. However there are some roadblocks to implementation of ORA's proposal. First, it is unknown how much rates will increase for those customers who stay on the default rates, as part of the calculation depends upon how many opt for the CPP. Second, there are practical rate-related differences among the IOUs. Specifically, Edison recently filed an application for rate reductions, so an increase to default TOU rates for its customers would be offset. On the other hand, the elimination of PG&E's surcharges is not expected to occur immediately, and SDG&E has no current plans to reduce rates. Third, the IOUs do not currently allocate either procurement costs or prospective savings by class or schedule, which is a necessary prerequisite to the ORA proposal. Nonetheless we believe that these practical problems must be weighed against the benefits of the ORA proposal

[73] ORA's Written Comments on the WG2 Reports, dated January 27, 2003, pp. 4 – 6.

and the likelihood that it will increase participation in demand response programs over the long term. ORA's conceptual proposal merits further exploration. Accordingly, we will require the IOUs to file a compliance filing outlining their assessment of the customer impacts of implementing the ORA proposal; indicating how they would implement both features of the ORA plan (its treatment of structural revenue shortfalls and its treatment of dynamic shortfalls); and identifying the currently available, or next available, ratesetting forum where the ORA proposal may be explored and implemented in the context of the IOU's overall rate design. ORA has requested that a workshop be held prior to the submission of these compliance filings and our order so provides.

Until the ORA proposal can be implemented, we will allocate the revenue shortfalls associated with the programs adopted in this decision on a system-wide basis, consistent with the recommendation of the IOUs and most other WG2 participants.

3. Program Administrative Costs

As shown in Attachment B, program administrative costs, which are comprised of O&M and A&G costs associated with the various activities necessary to implement the adopted demand response programs total $13.0 million and $7.0 million for calendar years 2003 and 2004, respectively. These costs included program monitoring and evaluation expenditures totaling $1.5 million in 2003 and $0.5 million in 2004. All costs attributable to the CPA DRP program should be covered by the IOUs in the following proportions: 45% each from PG&E and Edison, with 10% from SDG&E.

4. Capital Costs

As shown in Attachment B, capital costs for such items as advanced

attributable to the adopted demand response programs total $7.9 million, and $0 for calendar years 2003 and 2004, respectively. $4.5 million of the total $7.9 figure relates to the installation of additional AB29X meters on certain types of willing customers and it is not clear that all of those customers will select such meters. Thus, those capital costs could be considerably less than the amount projected. For purpose of allocation among the utilities, costs related to the CPA

[redacted]

DRP program should be allocated 45% each to PG&E and Edison, with 10% to SDG&E. Additional metering costs should be allocated at $2.5 million for PG&E, $1.5 million for Edison, and $0.5 million for SDG&E, with the proportional higher amount available to PG&E due to the number of agricultural customers in its territory with demands over 200 kW that do not yet have interval meters.

5. The Costs of Incentives

With our decision to approve only the professional technology assistance incentive, costs in this expenditure category for calendar years 2003 and 2004 are significantly reduced from the $11 million originally proposed to $3.41 million ($2.0 million in 2003 and $1.4 million in 2004).

There are expenditures shown in Attachment B as "other incentives" capped at a total of $0.9 million and $0.9 million in calendar years 2003 and 2004, respectively. These are the expenditures authorized in this decision for this

6. Imposition of Cost Cap

The costs (Program Administrative, Capital and "Other Incentive" Costs from the discussion above) for the demand response programs authorized in this decision for calendar years 2003 and 2004, are capped at the total amount of $23.7 million and 9.3 million, for calendar years 2003 and 2004, respectively. This total figure, $ 33.0 million, is exclusive of revenue shortfalls and CPA DRP costs, which are part of the DWR revenue requirement.

7. Cost Recovery Mechanisms

The respondent IOUs requested identical cost recovery mechanisms for programs adopted as a result of both WG2 and WG3. Consequently in our recent decision (D.03-03-036) dealing with WG3 issues, we adopted cost recovery mechanisms that apply to all Phase 1 programs, both those advanced by WG3 and WG2. Therefore it is unnecessary to address cost recovery mechanisms again in this decision.

J. Customer Education/Outreach

In the March 11th Report the WG2 participants have presented an implementation plan which builds upon the detailed Customer Marketing, Education and Recruitment Plans included in the December 13, 2003 WG2 Report. This plan assumes that the IOUs will assume the responsibility for marketing the adopted CPP/HPO and DBP programs to their large customers. As proposed, customer education includes extensive training for utility employees who have customer contact responsibilities, as well as development of customer education materials and education sessions, all designed to provide general familiarity with the adopted programs, program benefits, bill information, sign-up requirements, and enrollment procedures.

As proposed, marketing and recruitment efforts will emphasize higher potential customers, including those not currently participating in demand

response programs but who have participated in them in the past; and commercial and industrial customers whose operations offer peak load shifting opportunities. Some customer contacts will be made by phone, direct mail, or selected event participation. In addition, each IOU proposes to place CPP and DBP program information on its website. Throughout the life of these programs, communication with customers will continue via various program communication letters and ongoing one-on-one customer contact.

While adopting the WG2 customer education/outreach proposals in concept, we will also impose some requirements. We will require the IOUs to implement substantially similar customer education and outreach programs for the CPP/HPO and DBP; further these programs must be compatible with parallel activities of the CPA for its DRP programs. Marketing of incentives requires particular care so that incentives are not over-emphasized. We prefer to attract customers with as little use of incentives as is feasible in order to minimize costs, and in recognition of the fact that these incentives are not an intrinsic part of the tariffs, but merely a transitional tool. In connection with the adopted technical assistance rebate, professional technical assistance incentive certification and verification of load reduction should be handled by firms designated by the CEC. The IOUs should coordinate with the CEC to make every attempt to attract customers to these demand response programs who already have received subsidies from the state for installation of demand response equipment.

The customer education/outreach proposal submitted by WG2 leaves many specific implementation details to be resolved over time. We will not leave the resolution of these details to the sole discretion of the IOUs. Rather we will continue the WG2 process, requiring WG2 to be periodically briefed about IOU implementation proposals and to express alternative views. And in the event

there are disputes, we expect the WG2 facilitator initially to attempt to resolve them with the parties. If in the opinion of the WG2 facilitator, the IOU response to concerns insufficient, the WG2 facilitator will bring the matter to the attention of the assigned ALJ who will resolve the matter in consultation with the assigned commissioner.

K. Program Evaluation, Monitoring and Oversight

WG2 has proposed a comprehensive monitoring and evaluation plan.[74] Specifically, the monitoring plan would include recruitment and sign-up; tracking continuity; measuring actual patterns of demand response; IOU revenue impacts; participant expenditures; administrative costs; and reporting monitoring results. The evaluation plan will include such elements as identifying the nature of the participants; assessing load shape changes; understanding how to accomplish load impacts; estimating system benefits; estimating IOU revenue and cost impacts; and assessing whether tariff or program changes are necessary. The costs of the comprehensive measurement and evaluation plan are estimated at $861,000, and $275,000 for 2003 and 2004.

results, and comparative load reductions of those accepting the incentive vs. those who chose not to. Monitoring would be broadened to include reporting on the number of customers signed up for the rate protection incentive and the number and amount of true-up payments made after the first 12 months on the CPP or HPO tariff.[75]

WG2 participants also propose to monitor the technical assistance incentive designed to increase enrollment in the CPP and HPO tariffs as well as the IOU DBP. They plan to separately track and assess this incentive. There will be reporting on the number of sign-ups, the load reductions represented, and the incentive payments made. In addition, WG2 proposes to include the assessment of impacts of installing a variety of sub metering and data-logging devices on a sample of the technology-assisted customers, representing a broad range of customer types. Sub-metering and data-logging data will be correlated to total building loads and analyzed to determine how specific technologies contribute to total building load reductions. Costs for this effort include acquisition, installation, and removal of monitoring equipment; data collection and management; and data analysis and reporting. The CEC will supervise this work in coordination with the IOUs and the Energy Division. The costs of augmenting the comprehensive measurement and evaluation plan to assess the rate protection plan and incentives are projected to be $125,000 for 2003 and $250,000 for 2004 (see Attachment B), but these costs may be slightly higher than actual costs as they include the technology incentive which is not approved in this decision.

We are especially interested in monitoring and evaluating the impact of the incentives approved in this decision, so we will approve the supplemental

[75] Working Group 3 Report dated March 11, 2003, p. 38.

work suggested by WG2 in that area, as part of our overall approval of the plan as described above. The $460,000 estimated for this work is reflected in Attachment B. We also believe the CEC and the Energy Division must play a key role in the monitoring and evaluation process, as reflected in the WG2 proposal. And it is abundantly clear that an important coordination effort is needed to ensure that the appropriate data is collected and made available for analysis to support programmatic evaluation. The WG2 facilitator is designated to work with the IOUs and parties who wish to be included in this effort, to maintain the required level of coordination, including review of implementation plans, fine tuning of program implementation mechanics within the scope of this decision, and review of compliance filings or tariffs that may be required. In the event of disagreement that cannot be resolved within the WG2 process, the facilitator will bring the matter to the attention of the assigned ALJ who will resolve the matter in consultation with the assigned commissioner.

WG2 has suggested that Fall 2004 be a major point to evaluate the authorized tariffs and programs, but this decision has authorized tariffs without expiration dates and extended the period in which incentives can be offered through calendar year 2004. We will direct the IOUs, in coordination with the CEC, to conduct evaluation activities to be completed in the Fall of 2004, as input to a systematic review of demand response policy, tariff development, and program design to be conducted in the winter of 2004/2005.

V. Phase 2 of this Rulemaking

The Assigned Commissioner will issue a ruling scoping Phase 2 of this proceeding at the earliest opportunity. Such ruling will detail the issues to be addressed, and a timetable for their resolution, and will address the need, if any, for evidentiary hearings on some issues.

VI. Comments on Draft Decision

The draft decision of the ALJ was mailed to the parties in accordance with Pub. Util. Code §311(g) and the Commission's Rules of Practice and Procedure. On April 28, 2003, fourteen parties[76] filed opening comments, and on May 5, 2003, six parties[77] filed replies. We have considered the parties' views in light of the requirement that comments must focus on factual, legal, or technical errors in the draft decision, and that comments merely rearguing parties' positions will be accorded no weight (Rule 77.3). Consistent with Rule 77.3, and based on the current state of the rulemaking record, we have made various changes to the draft decision designed to strengthen its technical accuracy. These revisions range from the correction of minor typographical errors to more detailed changes that alter outcomes, as listed below and reflected throughout the decision.

A. Revisions: Program Details

We make certain technical revisions to Attachment C to clarify the CPP

[redacted]

First, the number of CPP operating days is 12 per year, except for summer of 2003 where there will be a proration due to implementation timing concerns. We also make technical revisions to both Attachment C and Attachment E (governing the IOU DBP program) to ensure consistency in the baseline

Given respondents' concerns about the complexities of integrating the CPA DRP into the IOUs' procurement and scheduling processes, we allow more time and a phased implementation approach (Ordering Paragraphs 8 and 9).

In response to comments, we allow the parties additional flexibility in their efforts to develop an RTP tariff in this proceeding (Finding 21; Ordering Paragraph 10).

B. Revisions: Customer Participation Issues

In response to comments noting that the record is not well-developed on the issue of agricultural customer participation, we limit the extension of the agricultural customer participation to a set of existing tariff schedules for PG&E and SDG&E. We require Edison to file a compliance filing detailing the tariff schedules they propose to include for agricultural participation. In doing so, we reject Edison's proposal that it transfer participating agricultural customers to discrete commercial accounts.

We adopt a set of conditions governing multiple meters at one customer site, as suggested by PG&E and others. We clarify the definition of customer site for purposes of multiple meter situations.

Finally, we make clarifying changes in connection with the bill protection incentive for CPP, extending the protection period from 12 to 14 months in order to provide customers protection during events that will be called through the fall of 2004. Conforming changes are made to Attachment C.

C. Revisions: Program Costs and Related Cost Issues

We have required the utilities to submit proposals to implement the ORA revenue shortfall proposal. In response to a suggestion made by ORA in its comments, we provide for a workshop moderated by Energy Division staff, to be held prior to the filing of the utility implementation proposals.

Attachment B has been revised to clarify that capital costs related to additional meters apply to all program offerings authorized in this decision. We also add additional columns to clarify costs already included in DWR's revenue requirement, as well as anticipated revenue reductions to the IOUs from customer participation in the programs or tariffs.

D. Revisions: Program Evaluation and Monitoring Oversight

We also correct an oversight in the draft decision, and include the $460,000 estimated cost of supplemental work suggested by WG2 in connection with an in-depth assessment that includes collecting quantitative information on how specific technologies performed in achieving demand reductions.

To facilitate the comprehensive monitoring and evaluation plan, we add a requirement that the IOUs provide all data and background information needed by those involved in the evaluation process, under appropriate confidentiality protection.

VII. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Lynn T. Carew is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The strategic development of demand response capability in the California energy market requires coordination among this Commission, the CEC, and the CPA; to meet this responsibility, these state agencies have used an interagency working model and three working groups to develop the record in Phase 1 of this rulemaking.

2. Throughout Phase 1, decisionmakers from the CPUC, CEC and CPA (the "Working Group (WG) 1 principals") provided policy guidance to a group of active parties interested in large customer demand response issues ("Working

Group 2 or WG2"), encouraging WG2 to develop a tariff or set of tariffs for use by large customers with average monthly demands of 200 kW and above, and to strive for "quick wins" that would take advantage of two key factors: the fact that 1) many large customers have interval meters in place due to AB29X, and 2) Summer 2003 presents conditions ideal to test how large customers who have such meters will respond to time-sensitive rates.

3. WG2 held thirteen noticed workshops, open to all active parties and facilitated by staff supporting the Working Group 1 principals, and during the period November 15, 2003 through March 11, 2003, WG2 produced four written reports. The participants attempted to develop consensus around a set of dynamic pricing proposals, but the diversity of opinion on key issues ultimately worked against the development of consensus on a "quick win" for Summer 2003.

4. The WG1 principals have developed a long-term vision and set of goals for demand response to help guide the efforts of participants in this proceeding. The vision statement provides a definition and simple goal statement, followed by objectives (reliability, lower power costs, and environmental protection), goals and principles (customer service, optionality, technology issues, IOU issues, and [illegible]

coordination), and a timeframe (phases for proof-of-concept, phased implementation for large customers, and residential implementation). This is an

6. There is agreement that achievable goals are as follows: for calendar year 2003: 150 MW for PG&E, 150 MW for Edison, and 30 MW for SDG&E; for calendar year 2004: 400 MW for PG&E, 400 MW for Edison, and 80 MW for SDG&E; for calendar year 2005: for all IOUs, 3% of annual peak demand for bundled service load; for calendar year 2006: for all IOUs, 4% of annual peak demand for bundled service load; for calendar year 2007: for all IOUs, 5% of annual peak demand for bundled service load.

7. The WG2 participants have been unable to develop one consensus tariff proposal given the diversity of views among large customer interests, respondents, and other parties.

8. Since no single demand response program or tariff satisfies all large customers, a portfolio or "mix" of demand response programs will appeal to the greatest number of customers.

9. While recognizing that mandatory tariffs/programs for large customers would produce the greatest demand response, it is reasonable to authorize voluntary program participation for large customers in the near term. Not all large customers are capable of immediately altering their manufacturing or production processes in order to respond to dynamic pricing tariffs and forcing their participation at this point will have serious unintended repercussions for the California economy.

10. The Association of California Water Agencies (ACWA) presented a Critical Peak Pricing (CPP) proposal widely regarded as a "no-lose" proposition as customers who do not respond pay no more than their current demand charges. Given our goal to develop programs providing meaningful demand response, and the fact that ACWA's proposal provides generous bill savings to participants who provide little or no demand response in return, there is

legitimate concern that ACWA's proposal does not provide a meaningful demand response resource.

11. The IOUs present a joint CPP proposal designed to appeal to commercial office buildings and other similarly-situated customers with large air conditioning loads, to be offered to large customers (>200 kW per month), most of whom are already equipped with interval meters due to Assembly Bill 29 of

[redacted]

the first extraordinary session of 2000-2001 (AB29X).

12. The City and County of San Francisco (CCSF) seeks to intervene in this proceeding out of concern that the statewide joint proposal does not adequately capture San Francisco's peak load profile.

13. It appears that the load, demand, and capacity characteristics of the San Francisco peninsula are unique in the PG&E territory and merit special consideration, although CCSF's broader concerns about transmission constraints and local generation issues are beyond the scope of this proceeding.

14. While the joint CPP proposal does not enjoy universal support, it is apparent that no single program appeals to all large users. The joint CPP proposal involves a relatively modest expenditure through 2004, provides customer choice, and also allows us to take advantage of the AB29X infrastructure already in place. Modifications to the Joint CPP Proposal allowing agricultural customer participation, certain multiple meter situations, multiple

customers (except exempted agricultural customers) with peak demand of 100 kW or more.

16. SDG&E's proposal to convert its existing pilot program, the Hourly Pricing Option (HPO), into a full-scale program has merit because the HPO, as modified, breaks new ground by expanding the hourly prices to semi-peak periods and expanding the number of hours for which hourly rates are revealed to the participant.

17. In order to add another type of demand response offering to the portfolio of offerings available to large customers, the IOUs propose to continue the existing Commission-authorized reliability-based demand bidding program, and also expand available demand bidding options, allowing participants to reduce demand voluntarily when requested by the IOUs in one of two ways: via 1) a price trigger, and 2) a system emergency trigger.

18. A customer-specific 10-day rolling average energy usage baseline, calculated "using the average of energy usage for the three highest days for the same hour during the past ten similar days prior to a DBP event" will be used to determine performance, as a means to address concerns that a simple 10-day rolling average may negatively bias temperature-sensitive customer loads. This determination should be made using a consistent methodology using the average of the highest kWh usage consumed over a specific period. For the CPP, the determination of a "high" day shall be based on the total kWh usage consumed over the peak period. For the DBP, the determination of a "high" day shall be based on the average per-kWh consumption over the bid duration period.

19. The DRP offered under the aegis of the CPA assists in meeting our stated demand goals because it is available to a much broader array of participants than the IOUs' DBP, which is limited to bundled customers. DRP is the one offering

that is available to direct access customers, a group whose participation in demand response programs is key to meeting statewide goals.

20. The Transmission and Distribution (T&D) Peak Capacity Proposal is presented as a pilot program for implementation in Summer 2003. It is designed to allow both direct access and bundled customers above and below 200 kW in T&D constrained areas to receive financial benefits in the form of reduced T&D charges when they take actions that provide benefits on constrained T&D systems. However the pilot description is very general, as are the specific concepts to be tested, and there is insufficient time to develop hourly prices for T&D constraint costs as inputs to this Summer 2003 demand response program.

21. Time did not permit the full exploration of the Infotility real time pricing (RTP) proposal, designed to test or identify 1) customer interest and response to a real time price signal across multiple building types; 2) customer preferences for baseline methodologies; 3) specific customer education requirements prior to participation in a two-part RTP tariff; 4) technical and administrative barriers to a full roll out; 5) customer satisfaction; and 6) "lessons learned." However there is keen interest among the active parties in developing a two-part RTP pilot or pilots or alternatives, which may use the Infotility proposal as a starting point.

22. Balancing our goal of maximizing participation in demand response programs against cost concerns, we will allow certain agricultural customers whose usage exceeds 200 kW to participate in the offerings authorized, if they currently have interval meters in place.

23. In furtherance of our desire to ensure the participation of agricultural customers in demand response programs, it is appropriate to require the respondents to provide accurate cost data relative to such participation by those agricultural customers who currently do not have interval meters in place.

24. A liberal meter aggregation policy will encourage participation, but that goal must be balanced against the unknown metering costs and our present lack of knowledge about small commercial customer demand response. Thus, we are not adopting an aggregation policy in this decision, but will explore the issue in Phase 2 of this proceeding. Instead, at this time, it is appropriate to limit participation by customers with multiple accounts to those situations where at least one meter of a multi-meter facility is already >200 kW and where an individual site is defined as in the applicable utility tariff rules.

25. Multiple program participation raises several concerns including two key ones: the possibility that customers will be compensated multiple times for the same load response and the possibility that potential load relief associated with a particular program will be double-counted.

26. There is significant customer inexperience with price-triggered demand response programs and a reluctance to spend the time and effort necessary to participate in these programs, as well as perceived risks about participation. Transitional incentives are one method to increase customer participation levels by overcoming these concerns.

27. The bill protection incentive available to those participating in the CPP and HPO programs will provide 100% bill protection, meaning that the participant pays no more than they would have had they remained on their original rate schedule, for the first fourteen months they are on the CPP or HPO tariff, but no later than December 31, 2005.

28. Under the bill protection incentive, the customer must actually reduce peak demand by a minimum of 3% per CPP event, averaged over the course of their fourteen-month participation. If they do not do so, they will not receive credit at the end of fourteen months. For customers on the HPO tariff, the 3%

reduction could be averaged over the entire time period of the customer's participation.

29. The bill protection option involves nearly no cost, as long as existing revenue requirements are established and shortfalls are collected through appropriate balancing mechanisms.

30. WG2 also proposed a technology incentive for participants in the CPP and HPO tariffs, as well as the IOUs' DBP, which would allow a rebate for installation and use of pre-approved technology that enhances the customer's

demand response. This transitional incentive

professional technical assistance component, without authorizing the additional hardware component of the proposed technology incentive package.

34. Approval of the professional technical assistance portion of the proposed technical incentive package, allowing a rebate for professional technical advice regarding installation of new equipment or modification of existing equipment or behavior, may spur customer participation at a more acceptable cost than that associated with the entire proposal for technical incentives.

35. In this decision we take several steps designed to augment customer participation in the adopted programs, including opening the tariffs and programs to certain agricultural customers, allowing certain multiple-meter situations, allowing multiple program participation in certain circumstances, as defined, and approving bill protection and professional technical assistance incentives. These actions will augment the expected MW demand response targets for 2003 and 2004 shown in Appendix B.

36. Our decision to reject the technology hardware portion of the transitional incentive proposal may diminish to some degree the expected MW contribution detailed in Appendix B related to the statewide CPP, HPO, and IOUs' DBP.

37. Because it has been the standard for rate design and demand-side management measure evaluation historically, the most relevant standard for determining cost-effectiveness for tariffs and programs designed to be part of a growing reliance upon demand response is the cost of a new peaker power plant.

38. Using several tests from the Standard Practice Manual, all programs authorized in this decision are cost-effective, except SDG&E's HPO, which did not pass one of the tests. However, given the limitations of the tests, all program proposals are attractive compared to investing in a new peaker of comparable MW size.

39. Customer participation in demand response tariffs and programs will

[redacted]

cause the IOUs to lose revenue (compared to authorized revenue requirement) because load reduction involves both a reduction in energy usage and a shift from energy use during peak periods in which existing rate designs accentuate revenue recovery. The exact amount of revenue loss depends upon many factors, including the nature and extent of customer participation in demand response programs, and other unknowns, such as offsetting energy purchase cost reductions attributable to effective demand response.

40. The estimated revenue shortfall impacts discussed in this decision are very conservative approximations because they assume no short-term commodity procurement cost savings associated with these reductions, and such savings certainly will exist, although their magnitude cannot be predicted in advance.

41. There are starkly differing recommendations regarding recovery of revenue shortfalls in this proceeding: the IOUs recommend recovery of revenue shortfalls from the entire system, whereas ORA argues that such shortfalls should be recovered from the large customer class(es), not system-wide. Under ORA's proposal, certain revenue shortfalls would be recovered from the non-CPP participants in the same sub-customer class, which will give non-participating (static rate) customers an incentive to switch to CPP or other dynamic tariffs and programs. There is merit in the ORA proposal, because it is designed to encourage program participation by sending appropriate cost signals. However, there are some near-term practical impediments to the

record consists of respondents' formal demand response programs/pricing options filed in compliance with the OIR; the official transcripts of five formally noticed WG1 meetings; the rulings following those meetings and written comments thereon; and the four WG2 reports and related rulings and written comments.

2. The tariffs and programs being developed in this proceeding should be explicitly linked with procurement planning in R.01-10-024.

3. The ACWA CPP proposal should not be adopted as it would provide generous bill savings to participants providing little or no demand response in return.

4. Since CCSF has demonstrated that it has a direct and substantial interest in the outcome of this proceeding that cannot be represented adequately by any other party, its motion to intervene pursuant to Rule 45 should be granted.

5. The joint CPP proposal should be approved, with certain modifications, because it involves a relatively modest expenditure through 2004, provides customer choice, and also allows us to take advantage of the AB29X infrastructure already in place.

6. SDG&E's proposal to convert its HPO pilot into a full-scale program and modify it by expanding the hourly prices to semi-peak periods, and expanding the number of hours during which hourly rates are revealed to participants, offers additional options to customers, and should be adopted. Consistent with D.02-01-062, SDG&E should be permitted to offer this program to customers

participation, as discussed in the text of this decision relative to multiple participation, multiple-meter situation, and inclusion of certain agricultural customers.

8. The CPA DRP should be adopted because it is available to a much broader array of participants than the IOUs' DBP, and is the one offering that is available to direct access customers, whose participation in demand response programs is key to meeting statewide goals.

9. IOUs should be able to dispatch from either demand bidding program, the IOU DBP or the CPA DRP, as both programs will be available to large customers.

10. Multiple program participation in the adopted programs should be allowed, provided that there are acceptable guidelines designed to avoid both double-compensation and double-counting, to the extent provided in this decision.

11. Because they meet the guidelines for avoiding double-compensation and double-counting of benefits, the following program combinations should be allowed: CPP and CPA DRP (or IOU DBP); OBMC and CPA DRP; CPA DRP and interruptible rates, subject to limitations discussed in this decision; and CPA DRP spot market options and interruptible rates, subject to limitations discussed in this decision.

12. The bill protection incentive, as modified in the preceding discussion to extend from twelve to fourteen months, should be approved for customers

14. A modest rebate in the amount of $50/kW of curtailable on-peak load for the costs associated with receiving professional technical assistance (related to the installation of new equipment or the modification of existing equipment or behavior) that leads to actual demand response, should be authorized.

15. In order to achieve demand response program stability, the programs authorized in this decision should be available well beyond calendar year 2004, and have no expiration date, although funding is authorized in this decision through calendar year 2004.

16. Since there are no remaining customers enrolled under PG&E's experimental real-time pricing tariff, Schedule A-RTP, and the joint proposal submitted in Phase 1 is a reasonable successor to that tariff, PG&E's Schedule A-RTP should be eliminated.

17. Since rate Schedule E-PBIP, a pilot authorized in D.02-04-060, has only one participant, and the WG2 participants see little harm in eliminating the pilot, the single participant should be encouraged and assisted to join another program or tariff and this tariff should be eliminated.

18. Notwithstanding the limitations of the tests from the standard practice manual, it is apparent that all of the programs and tariffs authorized in this decision are attractive when compared to investing in a new peaker power plant of comparable MW size; therefore, these specific tariffs and programs are sufficiently cost-effective to be authorized.

19. Given the concerns expressed by WG2 participants about the validity of the standard practice manual (SPM) tests, and importance of the process for developing inputs that accurately reflect the value of displaced supply-side power procurement costs, the parties should develop and advance proposed modifications to the SPM in Phase 2 of this proceeding.

20. Since ORA's conceptual revenue shortfall proposal merits further exploration, we should require the IOUs to make a compliance filing outlining their assessment of the customer impacts of implementing the ORA proposal.

21. The IOUs should be required to implement substantially similar customer education and outreach programs for the CPP/HPO and the DBP. Further, these programs should be compatible with the parallel activities of the CPA for its DRP.

22. In connection with the adopted technical assistance rebate, professional technical assistance, incentive certification, and verification of load reduction, should be handled by firms designated by the CEC. The IOUs should coordinate with the CEC to make every attempt to attract customers to these demand response programs who have already received subsidies from the state for installation of demand response equipment.

23. The comprehensive monitoring and evaluation plan proposed by WG2 in its December 13, 2002 report, as augmented by its March 11, 2003 report, should be adopted, in order to identify the nature of those participating in the adopted programs, assess load shape changes, understand how to accomplish load impacts, estimate system benefits, estimate IOU revenue and cost impacts, and assess whether tariff and program changes are necessary. WG2's proposal to supplement the monitoring and evaluation plan to assess the success of the bill protection and technical assistance incentives under the supervision of the CEC, should also be adopted.

ORDER

IT IS ORDERED that:

1. We hereby adopt the demand response goals enumerated in Table 1 for each IOU. To ensure that these goals are achieved, we direct the respondent IOUs to do the following:

   a. Take all appropriate steps to implement the dynamic pricing tariffs and programs adopted in this proceeding in order to achieve these goals;

   b. Recommend, as a result of monitoring and evaluation efforts, changes to the tariffs and programs adopted here, as well as additional tariffs and programs, to improve the cost-effectiveness of demand response activities;

   c. Include the MW targets for calendar years 2003 through 2007 in their procurement plans to be filed in R.01-10-024. To the extent that this decision is adopted after those plans are filed, the IOUs shall supplement or augment their filings in R.01-10-024 to reflect this requirement, including, in particular: numeric targets coinciding with the findings in this decision; documentation of the amount of demand response (price-triggered) to be achieved by July 1 of each calendar year (with the exception of 2003, where the goals shall be met by the end of the calendar year); which programs and/or tariffs the IOU will rely upon to achieve the targets; and a contingency plan for covering capacity needs should the utility fall short of meeting the demand response goals;

   d. Work with state agencies and the Independent System Operator (CAISO) to ensure that demand response programs and tariffs are appropriately considered in any resource adequacy or reserve requirements and emergency response activities.

2. The motion of the City and County of San Francisco (CCSF) to intervene in this proceeding is hereby granted. PG&E shall work with CCSF to create a localized marketing and recruitment area and triggering conditions for the existing CPP tariff proposal. PG&E and CCSF shall file and serve an advice letter containing the details of this localized plan within 30 days of the date of issuance of this decision.

3. The IOUs' joint Critical Peak Pricing (CPP) proposal is hereby authorized, subject to certain modifications relating to specific agricultural customer participation, multiple meter situations, multiple program participation, and the use of incentives.

4. SDG&E's proposal to convert the Hourly Pricing Option (HPO) approved in Resolution E-3782 into a full-scale tariff, and to modify HPO by expanding the hourly prices to semi-peak periods, is hereby adopted for SDG&E alone.

5. Consistent with D.01-05-032 SDG&E is authorized to offer its authorized CPP and HPO tariffs to customers with peak demands of 100 kW or more, consistent with the text of this decision.

6. The IOUs' Demand Bidding Program (DBP) as presented in the March 11, 2003 WG2 Report, is hereby adopted, subject to the following modifications: First, under circumstances specified elsewhere in this decision, we allow

decision, which IOUs may use to satisfy their demand response goals established herein.

8. The IOUs shall immediately develop with the CPA and the Department of Water Resources (DWR), as necessary, a mutually acceptable interim mechanism for allocating the CPA DRP resources that they schedule in 2003 with the CAISO. IOUs and CPA shall also develop a permanent proposal, based on the experience in Summer 2003, unless such an alternative mechanism is developed in the procurement proceeding. Within 120 days of the date of issuance of this decision, the IOUs shall file and serve a joint compliance filing containing this information.

9. Within 30 days of the date of issuance of this decision, the IOUs shall file and serve an advice letter with the Commission's Energy Division containing their DRP implementation plan. The issues of operation and scheduling of CPA's existing programs and new multiple program combinations cannot all be resolved immediately, so we require the plan to describe how these concerns can be addressed and solved in phases. The preparation of the plan shall be coordinated with the CPA. Phase 1 of the plan shall include, at a minimum, how the IOUs will coordinate their procurement scheduling activities with the CPA DRP Call Option subprogram in order to ensure that the DRP resources are used when it is cost effective to do so, as well as other efforts to be implemented in summer 2003. The plan shall also contain a timeline identifying when additional phases are expected to start and describe, in a manner acceptable to CPA, the details of the implementation of those phases.

10. In concert with the WG2 participants, the respondent IOUs shall develop a pilot or pilots or consider alternatives, which may use the Infotility pilot proposal as a starting point, testing two-part RTP tariff design features under a schedule to be determined. The cost of the two part RTP pilot(s) or alternatives

authorized in this decision shall not exceed $2.8 million, and the actual costs of the pilots or alternatives shall be recorded and recovered using the cost recovery mechanisms authorized for the Statewide Pricing Pilot authorized by this Commission in D. 03-03-036. Before initiating any two-part RTP pilot(s) or alternatives, the respondent IOUs shall present the details of the proposal in

[redacted]

advice letter filing to the Commission's Energy Division for approval; the advice letter shall include a provision detailing how the IOUs propose to provide informational reports and pilot results to the WG2 participants.

11. Agricultural customers, whose peak demand exceeds 200 kW and who have interval meters in place and who are on PG&E's Schedule AG-4 and AG-5, options C and F, or SDG&E's Schedule PA-T-1, are authorized to participate in the programs and tariffs adopted in this decision. Within 15 days of the effective date of this decision, Edison shall define the agricultural schedules to be eligible in its territory. Within 45 days of the date of issuance of this decision, in preparation for Phase 2 of this proceeding, respondents shall file and serve in this docket a compliance filing detailing the projected cost of allowing agricultural customers whose usage exceeds 200kW and who currently lack interval meters to participate in the specific demand response programs authorized in this decision.

DRP spot market options and interruptible rates, subject to limitations discussed in this decision.

14. The bill protection incentive for customers participating in the CPP and HPO tariffs, as proposed by WG2 to include the performance requirement, the site visit requirement, and including a 14-month participation requirement, is hereby approved; in its tariff filing, SDG&E shall specify the exact nature of the performance requirement for HPO customers.

15. A maximum of $50/ kW for professional technical assistance (related to the installation of new equipment or modification of existing equipment or behavior), that leads to actual demand response by customers participating in the CPP/HPO tariffs or IOU DBP, is hereby authorized. The participating customer shall receive a transitional incentive equal to 50% of the potential payment upon certification of potential on-peak load reductions. The remainder of the incentive (the 50% remainder) shall be paid after the customer has shown a calculated peak demand reduction equal to at least 50% of their estimated load drop per CPP event, as averaged over four consecutive CPP or HPO months, while on the program, and before December 31, 2005. If this minimum level of measured load-shifting does not occur, the customer shall not receive the 50% remainder payment. To determine performance, the kW drop will be determined using the customer baseline proposed in the March 11 WG2 report.

16. In the Fall of 2004, the IOUs shall file evaluations for all tariffs and programs authorized in this decision, as well as those authorized in D.02-04-060 in our interruptibles rulemaking, for the purpose of making any necessary

17. PG&E's experimental real-time pricing tariff, Schedule A-RTP, is hereby eliminated.

18. The pilot and associated rate Schedule E-PBIP, authorized in D.02-04-060, is hereby eliminated.

19. Within sixty (60) days of this decision, the respondents shall file a proposal to recover net revenue losses from participation in the voluntary CPP tariff from within the class that caused the losses. The proposal shall be reviewed in this proceeding to identify an appropriate forum – Phase 2 or another proceeding -- to address the merits of the proposal. Each proposal shall include:

a. identification of existing or proposed new means of tracking gross revenue losses from CPP participants in each tariff;
b. a description of each element of gross revenue losses, (e.g. structural shortfall from CPP participants who do not respond to CPP signals, revenue shortfall from active CPP participants, etc.);
c. identification of existing or proposed new means of tracking procurement costs avoided by CPP participants in each tariff;
d. identification of methods for periodically estimating the aggregate benefits from market price reductions induced by load reductions of CPP participants and proposed means of allocating these benefits to each tariff;
e. identification of methods for determining net revenue losses allocated to each tariff to be recovered from within that tariff;
f. suggested ratemaking proceedings in which net revenue losses by tariff

21. For the authorized tariffs and programs, aggregate program administrative costs shall be limited to $13.0 million and $7.0 million for calendar years 2003 and 2004, respectively. Aggregate capital costs are limited to $7.9 million and $0 for 2003 and 2004, respectively. Aggregate incentive costs, including "other incentives" not already covered in the DWR revenue requirements, are limited to $2.9 and $2.3 million for 2003 and 2004, respectively.

22. The total cost expenditures authorized as a result of this decision are capped at $33.0 million over the two calendar years, exclusive of revenue shortfalls and costs related to "other incentives" which are part of the DWR revenue requirement. Each IOU shall use the cost recovery mechanisms previously adopted in D.03-03-036 as applicable to all Phase 1 programs.

23. The WG2 customer education/outreach proposals contained in the December 13, 2002 report, as augmented by the March 11, 2003 report, are adopted in principle. The IOUs shall implement substantially similar customer

needed to complete this plan, under appropriate confidentiality protections, as needed, to those involved in the evaluation process. The IOUs shall also make this data available to academic researchers, also under suitable confidentiality protection, to facilitate understanding of demand response. The CEC in coordination with the Energy Division shall supervise this work.

25. The WG2 facilitator is designated to work with the IOUs and parties who wish to be included in the coordination effort that is necessary to ensure that the appropriate monitoring and evaluation data is collected and made available for analysis. These efforts include, among other things, review of implementation plans, fine tuning of program implementation mechanics, and review of compliance filings or tariffs that may be required. In the event of disagreement that cannot be resolved within the WG2 process, the facilitator will bring the matter to the attention of the assigned ALJ, who will resolve the matter in consultation with the assigned Commissioner.

26. The IOUs, in coordination with the CEC and the Energy Division, shall conduct evaluation activities to be completed by the Fall of 2004, as input to a systematic review of demand response policy, tariff development, and program design to be conducted in the Winter of 2004/2005.

27. Any necessary modifications or refinements to tariff or program designs beyond those authorized in this decision that arise during the implementation phase, to the extent they cannot be resolved within the WG2 process, shall be requested by formal motion, filed and served on all parties of record. The assigned ALJ, in consultation with the WG2 facilitator and the Assigned Commissioner, is authorized to make any necessary modifications by ruling.

28. Within ten days of the issuance of this decision, the IOUs shall file advice letters containing the tariffs required to implement the adopted offerings. The [illegible] effective 20 days after their filed date, unless otherwise

suspended by Energy Division. To the extent the attachments to this decision are more definitive than the decision text, the attachments govern. The following are the offerings, as modified in this decision:

- The Joint IOU CPP proposal, following the parameters specified in Attachment C. SDG&E's tariffs shall reflect the authority granted to it to offer the CPP to its customers with monthly peak demands of 100 kW or more.
- For SDG&E, a tariff implementing the authority granted to it to modify the

[redacted]

full-scale tariff, and to offer HPO to its customers with monthly peak

31. The Joint Commenters' Motion for Acceptance of Late Filed Comments is hereby granted.

This order is effective today.

Dated June 5, 2003, at San Francisco, California.

MICHAEL R. PEEVEY
President

GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I will file a dissent.

/s/ LORETTA M. LYNCH
Commissioner

I will file a dissent.

/s/ CARL W. WOOD
Commissioner

ATTACHMENT A

California Demand Response: A Vision for the Future (2002-2007)

Joint statement for consideration by the California Energy Commission, Public Utilities Commission, and Consumer Power and Conservation Financing Authority

This vision is intended as a broad statement for encouraging demand responsiveness in California. It should be read in the context of maximizing the efficient use of resources, while maintaining the economic vitality of businesses in the state, as well as the health, welfare, and comfort of residential electricity users.

We acknowledge that demand response is one resource among many that may be procured by utilities on behalf of their electricity customers. We also seek to make the most cost-effective investments in demand response from an overall societal perspective.

Finally, this vision is intended as a starting point, and should not be interpreted as prejudging the outcome of analysis and recommendations delivered by the working groups to the policymakers in this proceeding.[78] Further, we intend to use this vision as a guide to our efforts, will continue to reevaluate its validity and assumptions as we progress, and will make any modifications, as necessary and appropriate, when new information becomes available.

Definition

DEMAND RESPONSE gives an individual electric customer the ability to reduce or adjust their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal.

Vision

All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by no later than 2007.

[78] CPUC rulemaking R.02-06-001 on policies and practices for advanced metering, demand response, and dynamic pricing.

Objectives

Reliability

- Timely demand response (within minutes or hours) from customers can offset the need for investment in generation, transmission, and/or distribution
- Demand response activities should be designed to achieve a target of 5% reduction in peak demand by 2007
- Cost-effective demand response should be used to meet a portion of reserve requirements
- Numerous and diverse customers voluntarily reducing or shifting their demand in response to economic signals is preferable to controlled outages during power system emergency situations

Lower power costs

- During high-cost periods, demand response can assist in bringing supply and demand into balance by signaling to the consumer the actual costs of buying power at the margin and/or investing in new power resources, thereby lowering overall wholesale electricity costs for all customers
- Timely demand response can, along with other wholesale market measures, help mitigate wholesale market power and ensure reasonable prices
- To encourage demand response, a long-term objective is designing retail rates that dynamically incorporate the marginal cost of providing electricity service
- Demand response activities and infrastructure should be designed to be cost-effective from a societal perspective

Environmental protection

- Reducing consumer electricity usage during peak periods can help reduce fuel use and therefore overall air emissions by reducing output from marginal generation units
- The agencies' definition of demand response does not include or encourage switching to use of fossil-fueled emergency backup generation, but high-efficiency, clean distributed generation may be used to supply on-site loads

Goals and Principles

Customer Service

- Electric consumers in California should be made aware of the time-variable nature of electricity costs and of general steps they can take to help lower those costs

- All customers that desire it should have greater access to information about

[redacted]

their own electricity use, at least weekly or daily, with the option for hourly or more frequent data
- Technologies to enable demand response may also provide other customer service benefits including outage detection and management, power quality management, and other information capabilities
- Demand response programs and tariffs should be designed to be customer-friendly, simple, and easy to understand, as well as to minimize customer confusion and allow for continuity among options

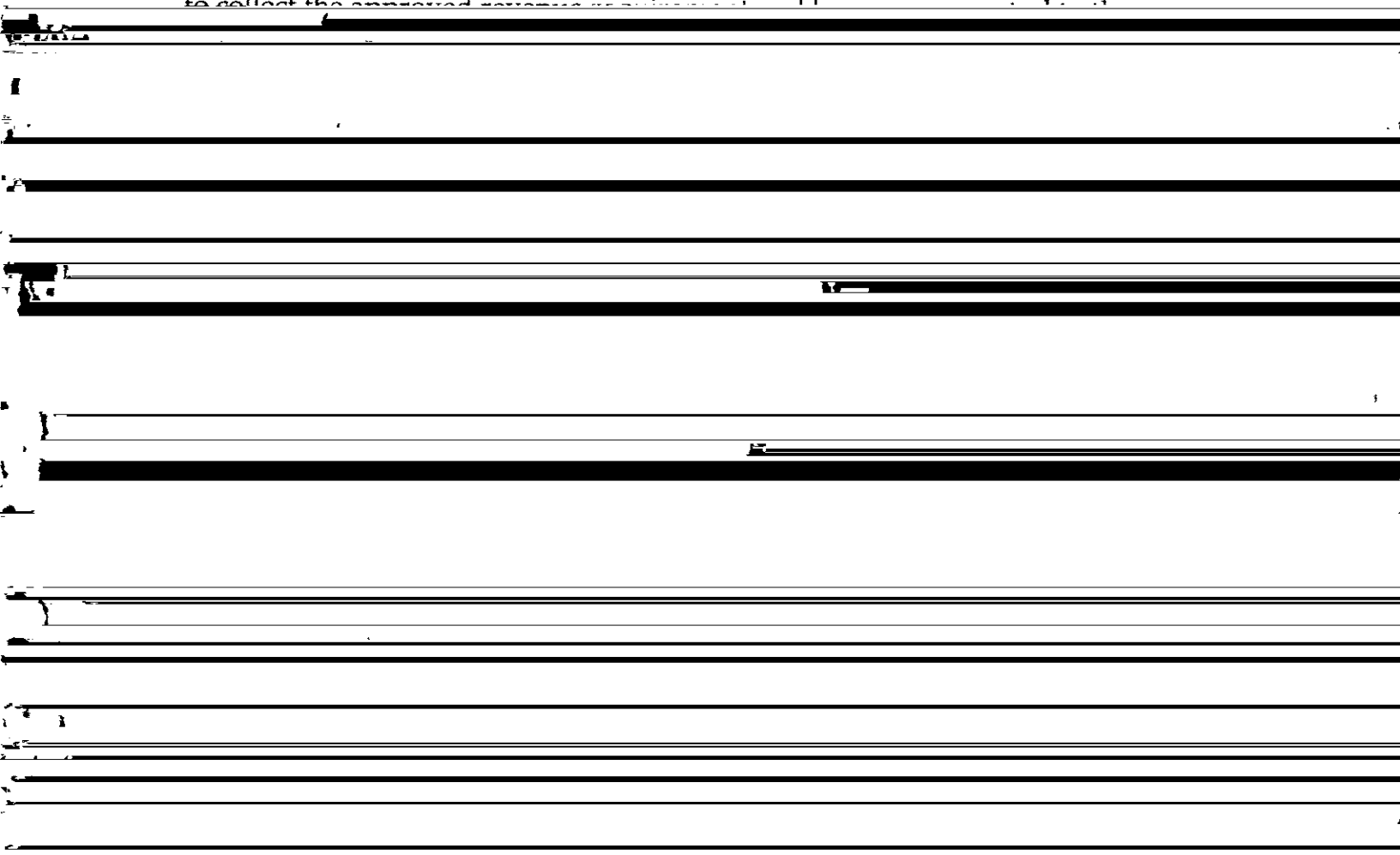
Optionality

- Customers should have the ability to choose voluntarily among various tariff options, including:
  - Very large customers (over 1 MW): Hourly real-time pricing (RTP), critical peak pricing (CPP), or Time-of-Use (TOU) Pricing
  - Large customers (200 kW to 1 MW): CPP, TOU or RTP
  - Residential and small commercial customers (under 200 kW): CPP, TOU or flat rate (the latter with an appropriate hedge for risk protection)
- Customers should also have the option to participate voluntarily in programs where they are paid to provide demand reduction as a dispatchable resource,

- State building code (Title 24) updates provide a cost-effective opportunity to introduce demand response technologies during the construction of new buildings or renovation of existing buildings

Investor-Owned Utility (IOU) Issues

- IOUs should be reimbursed for all reasonable expenditures on infrastructure and administration to enable demand response
- IOUs should be required to procure demand response resources as a portion of their overall procurement portfolio (target of 5% of peak demand by 2007) and as a portion of their reserve requirements beginning in 2004
- IOUs should also be provided an incentive mechanism to encourage the best choices for ratepayers
- Operation of an IOU's overall demand response portfolio should be designed to collect the approved revenue requirement [illegible]



IOU (e.g., revenues stay consistent with costs), with periodic true-ups as necessary

- All IOU demand response efforts should be periodically evaluated to determine past performance and improve future effectiveness

Coordination Issues

- Effective demand response efforts will require coordination among the agencies

- Pilot programs implemented to gather further information on smaller customer demand response and tariff or program preferences
- Business cases for phased implementation of universal demand response capability (potentially with automated meter reading technology) developed and evaluated, including cost-effectiveness analysis

2004: Phased implementation begins

- Full menu of demand response programs and dynamic pricing tariffs implemented for large and very large customers
- Small commercial and residential pilot program information evaluated
- Vision and timeframe reevaluated
- Technological options reevaluated, based on pilot program results
- Small and medium commercial customer infrastructure deployment phase begins

2005 and 2006: Residential implementation

- Major mass-market education effort initiated
- Full menu of tariff and program options rolled out to residential customers by the end of 2006

(End of ATTACHMENT A)

ATTACHMENT B

Attachment B
DEMAND RESPONSE TARIFF/PROGRAM COST AND INCREMENTAL REVENUE REQUIREMENTS

Program or Tariff Sponsor	Program Name	Impacts in 2003 (MW)	Program Administration Costs (O&M + A&G) for Calendar Year 2003 (4)	Capital Costs for Calendar Year 2003 (3)	Transitional Technical Incentive Calendar Year 2003	Other Incentives in 2003	Total Amounts Proposed for Approval via R.02-06-001 for 2003	Incentives Already Approved via DWR Rev. Req.	Revenue Reductions from Participants
Joint UDC's	CPP	131	$3,848,000	$400,000	$1,272,717	$0	$5,520,717	$0	$8,267,000
PG&E	DBP	16	$310,000	$164,000	$75,758	$239,417	$789,175	$0	$0
SCE	DBP	34	$684,000	$0	$641,026	$664,957	$1,989,983	$0	$0
SDG&E	DBP	3	$208,000	$7,000	$8,333	$17,652	$240,985	$0	$3,000
SDG&E	HPO	2	$150,000	$140,000	$0	$0	$290,000	$0	$426,000
CPA	DRP	225	$3,700,000	$2,500,000	$0	$0	$6,200,000	$12,750,000	$2,835,000
WG2	2-part RTP	0	$2,655,000	$145,000	$0	$0	$2,800,000	$0	$0
WG2	Additional meters	0	$0	$4,500,000	$0	$0	$4,500,000	$0	$0
WG2	Comp. M&E Plan	0	$861,000	$0	$0	$0	$861,000	$0	$0
WG2	M&E of Incentives	0	$125,000	$0	$0	$0	$125,000	$0	$0
WG2	M&E Data Collection	0	$460,000	$0	$0	$0	$460,000	$0	$0
Total Expenditures/Impacts (1)		411	$13,001,000	$7,856,000	$1,997,833	$922,026	**$23,776,860**	**$12,750,000**	**$11,531,000**
Total Annual Incremental Revenue Req. (2)			$13,001,000	$942,720	$1,997,833	$922,026	**$16,863,579**		
Annualized Benefits (5)							**$36,900,000**		

Notes:

(1) Revenue reductions as a result of participant load shifts/reductions cause revenue shortfalls, but these may be partly offset by power procurement cost reductions.

(2) Assumes a 10% rate of return, with a net-to-gross multiplier of 2 recovered over ten years.

(3) Capital investments for CPA DRP include $2,500,000 to support utility incremental software development for better handling of meter data to support DR customers consistent with ISO practices.

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(4) For CPA DRP administrative expenses, $1.6 million is for the IOUs, and $2.1 million is for CPA, of which $500,000 is for The Energy Coalition.
(5) Utility Avoided Costs (UAC) for CPP, DBP, HPO and DRP. UAC is based on costs avoided from building a new peaker plant (a fixed cost of $85 per kW-yr., and a fuel cost of $3.50 per mmBTU). The size of these benefits reflects the positive cost-effectiveness results reported in the WG 2 report dated 3/11/03. The UACs for CPP, DBP and HPO are found in Appendix E of the 3/11 WG 2 report (Both Incentives scenario), while the UAC for the DRP is in Appendix C of the 1/16 WG 2 report, (divided by two for 2003 to reflect a phased implementation over 2003-2004.)

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Program or Tariff Sponsor	Program Name	Impacts in 2004 (MW)	Program Administration Costs (O&M + A&G) for Calendar Year 2004 (4)	Capital Costs for Calendar Year 2004 (3)	Transitional Technical Incentive Calendar Year 2004	Other Incentives in 2004	Total Amounts Proposed for Approval via R.02-06-001 for 2004	Incentives To Be Approved via DWR Rev. Req.	Revenue Reductions from Participants
Joint UDC's	CPP	371	$2,642,000	$0	$597,791	$0	$3,239,791	$0	$5,670,000
PG&E	DBP	74	$25,000	$0	$431,818	$67,565	$524,383	$0	$0
SCE	DBP	37	$25,000	$0	$192,308	$444,995	$662,303	$0	$0
SDG&E	DBP	11	$25,000	$0	$50,000	$373,043	$448,043	$0	$0
SDG&E	HPO	11	$50,000	$0	$152,905	$0	$202,905	$0	$794,000
CPA	DRP	450	$3,700,000	$0	$0	$0	$3,700,000	$25,500,000	$23,413,000
WG2	2-part RTP	0	$0	$0	$0	$0	$0	$0	$0
WG2	Additional meters	0	$0	$0	$0	$0	$0	$0	$0
WG2	Comp. M&E Plan	0	$275,000	$0	$0	$0	$275,000	$0	$0
WG2	M&E of Incentives	0	$250,000	$0	$0	$0	$250,000	$0	$0
Total Expenditures/Impacts (1)		954	$6,992,000	$0	$1,424,822	$885,603	**$9,302,425**	**$25,500,000**	**$29,877,000**
Total Annual Incremental Revenue Req. (2)			$6,992,000	$942,720	$1,424,822	$885,603	**$10,245,145**		
Annualized Benefits (5)							**$85,305,000**		

Notes:

(1) see 2003 table above

(2) see 2003 table above

(3) incremental cost is due to levelizing capital expenditures over ten years, see 2003 table.

(4) see 2003 table above

(5) see 2003 table above

(End of ATTACHMENT B)

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ATTACHMENT C

ATTACHMENT C
Critical Peak Pricing Tariff

The purpose of the Critical Peak Pricing (CPP) tariff is to achieve demand reductions from customers when electricity supply is low or when spot market power prices are high.

1.1. **Applicability**

1.1.1. This tariff schedule is applicable to bundled service customers in

1.2.8. Critical peak hours shall be aligned with each IOU's respective commercial peak periods.

1.2.9. For the summer of 2003, the maximum number of critical peak days will be prorated to account for the late starting date.

1.3. Critical Peak Rate Effects

1.3.1. This tariff shall be designed with two time periods during critical peak days, a high-price period and a moderate-price period of approximately equal duration.

1.3.2. The high-price period energy charge shall be five times the customer's otherwise applicable on-peak energy charge. SDG&E shall use a multiple factor that will closely align its energy charges with the other IOUs (approximately a factor of 10).

1.3.3. The moderate-price period energy charge shall be three times the customer's otherwise applicable partial-peak energy charge. SDG&E shall use a multiple factor that will closely align its energy charges with the other IOUs (approximately a factor of 5).

1.3.4. On non-critical peak days, the customer's on-peak and partial peak energy charges shall be discounted such that the critical peak rate schedule is revenue neutral in comparison to the otherwise applicable rate schedules.

1.4. Transitional Incentive Options

1.4.1. Customers on the CPP tariff may select from two types of transitional incentive options: bill protection and technical assistance. Customers may elect to receive one of these incentives, both incentives (sequentially or simultaneously), or none.

1.4.2. Both transitional incentive options shall expire on December 31, 2005.

1.4.3.

1.4.4. The bill protection option shall provide 100% protection (the customer pays no higher than what it would pay under its otherwise

1.4.4.3. To receive the benefit of a lower CPP bill, customers shall reduce peak demand by a minimum of 3% per CPP event averaged over the course of the CPP months during the customer's 14 months of bill protection.

1.4.4.4. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three days with highest total energy usage during the peak period (excluding other CPP days or other days the customer was otherwise paid to reduce power or the customer was subject to a rotating outage) prior to a CPP event.

1.4.4.5. Bill protection benefits are computed on a cumulative basis at the end of the bill protection period and, if warranted, shall be received as a credit on the customer's bill following the end of the bill protection period.

1.4.5. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment events.

1.4.5.1. Customers shall receive a rebate (not to exceed actual costs) based on no more than $50 per kW of curtailable on–peak load for technical assistance that modifies existing equipment or behavior.

1.4.5.2. Customers shall receive 50% of the rebate upon certification by a professional engineer of potential on-peak load reductions.

1.4.5.3. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction equal to at least 50% of their estimated (projected by the professional engineer) load drop per CPP event as averaged over four consecutive CPP months. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate.

1.4.5.4. The method of measuring demand reduction is the same as described in Section 1.4.4.4.

(END OF ATTACHMENT C)

ATTACHMENT D

ATTACHMENT D
Hourly Pricing Option Tariff

The purpose of the Hourly Pricing Option (HPO) tariff is to provide a day-ahead price signal to create an incentive for customers to avoid peak usage and or shift usage to off-peak periods. The HPO tariff was approved as a voluntary pilot program for SDG&E in August 2002. The existing HPO tariff is modified in the following manner:

1.1. **Applicability**

1.1.1. This tariff schedule is applicable to customers with demands greater than 100 kW in San Diego Gas and Electric (SDG&E) service territory.

1.1.2. Customers shall have an advanced metering system (meter, communication pathway, and internet access to the usage data) as installed pursuant to AB29x, or the equivalent.

1.1.3. Customers on this tariff must agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program.

1.2. **Hourly Pricing**

1.2.1. The hourly pricing mechanism currently provided during on-peak periods shall also apply to semi-peak periods.

1.3. Transitional Incentive Options

1.3.1. Customers on the HPO tariff may select from two types of transitional incentive options: bill protection and technical assistance. Customers may elect to receive one of these incentives, both incentives (sequentially or simultaneously), or none.

1.3.2. Both transitional incentive options shall expire on December 31, 2005.

1.3.3. The bill protection option shall provide 100% protection (the customer pays no higher than what it would pay under its otherwise applicable rate schedule) for the customer for a maximum of 14 months.

1.3.4.1. The bill protection option shall be capped at 100 MWs.

1.3.4.2. If a customer leaves the HPO prior to the end of their 14-month commitment they shall receive no bill protection for any month.

1.3.5. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment events.

1.3.5.1. Customers shall receive a rebate (not to exceed actual costs) based on no more than $50 per kW of curtailable on–peak load for technical assistance that modifies existing equipment or behavior.

1.3.5.2. Customers shall receive 50% of the rebate upon certification by a professional engineer of potential on-peak load reductions.

1.3.5.3. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction equal to at least 50% of their estimated (projected by the professional engineer) load drop as averaged over four consecutive HPO months. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate.

1.3.5.4. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three highest-use days for the same hour during the past 10 similar days.

(END OF ATTACHMENT D)

ATTACHMENT E

ATTACHMENT E
Demand Bidding Program

The DBP is an existing program recently modified by D.02-07-035. The purpose of the modified Demand Bidding Program (DBP) is to provide customers an opportunity to voluntarily bid demand reductions as a means of off-setting the utilities' procurement of energy supply when the cost of that energy exceeds a certain price. The DBP is modified in the following manner:

1.1. **Applicability:** This program is applicable to customers with demands greater than 200 kW in Pacific Gas & Electric, Southern California Edison and San Diego Gas and Electric (SDG&E) service territories.

1.1.1. Customers shall have an advanced metering system (interval meter, communication pathway, and internet-based access to usage information) as installed by AB29x, or its equivalent.

1.1.2. Customers on this tariff must agree to allow the CEC or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program.

1.2. **Price Trigger**

1.2.1. Utility procurement departments shall forecast an hourly price offer on a day-ahead basis. This price offer is to remain confidential, which participating customers will agree to as a condition of the agreement to accept service on this tariff.

1.2.2. The DBP is triggered in those hours where the forecast price offer exceeds $0.15 per kWh for four consecutive hours between noon and 8 pm.

1.2.3. The incentive paid to participants shall be the product of the price offer and the amount of demand load reduction.

1.2.4. The demand load reduction must be greater than or equal to 50% of the bid, up to 150% of the bid.

1.2.5. Participants must commit to a minimum bid of 100 kW per hour.

1.2.6. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three highest-use days for the same hour during the past 10 similar days (excluding other DBP days or other days the customer

was otherwise paid to reduce power or the customer was subject to a rotating outage) prior to a DBP event. The three highest-use days will be determined on the basis of customer's total energy usage during the scheduled bid period for the DBP.

1.2.7. Participants will have the option to designate a pre-bid amount in which they will only be notified of a DBP event when the price trigger meets or exceeds their specified pre-bid amount.

1.5. Emergency Trigger

1.5.1. The IOUs may activate the DBP Emergency Event option, on a 'day-of' basis, when it is deemed necessary to offset outstanding system issues that may affect system reliability.

1.5.2. When a customer signs up for the program, the participant must designate a Committed Load Reduction amount that they agree to reduce their load by in the occurrence of an Emergency Trigger DBP event.

1.5.3. The incentives paid to participants during Emergency Trigger events shall be the product of their energy reduction and $0.50 per kWh.

1.5.4. The demand load reduction must be greater than or equal to 50% of the bid, up to 150% of their Committed Load Reduction.

1.5.5. Emergency Test Trigger

1.5.5.1 The utilities may activate the DBP with a simulated emergency event test trigger twice per year.

1.5.5.2 Emergency test events shall be no longer than 4 hours.

1.5.5.3 The incentive paid to participants shall be the product of their demand reduction and $0.50 per kWh per test event.

1.5.5.4 The demand load reduction must be greater than or equal to 50% of the bid, up to 150% of their Committed Load Reduction bid.

1.5.5.5 The method of measuring the demand reduction shall be the same as described in Section 1.2.6.

1.6. Transitional Incentive Option

1.6.1. Customers on the DBP may select a technical assistance incentive option.

1.6.2. This option shall expire on December 31, 2005.

1.6.3. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment events. Customers shall receive a rebate (not to exceed actual costs) based on $50 per kW of curtailable on-peak load for technical assistance that modifies existing equipment or behavior.

1.6.3.1. Customers shall receive 50% of the rebate upon certification by a professional engineer of potential on-peak load reductions.

1.6.3.2. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction of at least 50% of their estimated (projected by the professional engineer) load drop as averaged over all DBP events or tests. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate. A minimum of two DBP events or tests must be successfully completed.

1.6.3.3. For the purpose of measuring demand reduction, kW drop is to be estimated as the difference between a customer's specific baseline for that hour and the customer's actual energy usage during that hour. The customer-specific baseline is a 10-day rolling average energy usage determined on an hourly basis, using the average of energy usage for the three highest-use days for the same hour during the past 10 similar days (excluding other DBP days or other days the customer was otherwise paid to reduce power or the customer was subject to a rotating outage) prior to a DBP event. The three highest-use days will be determined on the basis of customer's total energy usage during the scheduled bid period for the DBP.

(END OF ATTACHMENT E)

Agenda Date: 03/01/01
Agenda Item: 6A

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102

ENERGY

IN THE MATTER OF THE PETITION OF THE FILINGS OF THE COMPREHENSIVE RESOURCE ANALYSIS OF ENERGY PROGRAMS PURSUANT TO SECTION 12 OF THE ELECTRIC DISCOUNT AND ENERGY COMPETITION ACT OF 1999	))))))	FINAL DECISION & ORDER BPU DOCKET NOS: EX99050347, EO99050348, EO99050349, EO99050350, EO99050351, GO99050352, GO99050353, GO99050354

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Decision and Order memorializes and provides the reasoning for the decisions taken by the Board of Public Utilities ("Board" or "BPU") in this matter at the December 6, 2000 and the March 1, 2001 public agenda meetings. The structure of this Decision and Order is set forth in the following Table of Contents.

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I. INTRODUCTION

The Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq., ("the Act" or "EDECA") demands re-evaluation of existing energy efficiency policies and programs, N.J.S.A. 48:3-60(3) or, as the Act defines, an analysis of "existing market barriers to the implementation of energy efficiency and renewable technologies that are not, or cannot be delivered to customers through a competitive marketplace." Id. This analysis has led to careful consideration of a myriad of programs and technologies, ranging from the familiar energy efficiency appliance programs to new energy efficiency programs and Class I renewable energy programs to promote, "electric energy produced from solar technologies, photovoltaic technologies, wind energy, fuel cells, geothermal technologies, wave or tidal action, and methane gas from landfills or a biomass facility." N.J.S.A. 48:3-51. With this Comprehensive Resource Analysis ("CRA") Order, and in the tradition of encouraging energy efficiency, the BPU takes another step to address the challenges of the Electric Discount and Energy Competition Act. With the Act's elimination of the traditional retail monopolies held by electric public utilities for electric power generation and supply services, New Jersey energy consumers are being afforded the chance to access the competitive market for these services, and to select the energy supplier of their choice. This dramatic public policy change also makes it necessary to re-evaluate existing Demand Side Management ("DSM") policies and programs, to consider new energy efficiency alternatives to replace current programs in New Jersey, and to foster new energy resources in such alternatives as renewable energy sources. The Board notes that some programs are inherently tied to service reliability issues by their ability to curb demand. This focus on demand reduction is particularly important as the United States focuses its attention on shortages in New England and New York, as well as the difficulties faced by California energy markets.

After a process involving a wide spectrum of participants, including the electric and gas utilities, the Division of Ratepayer Advocate ("DRA"), environmental groups, the renewable energy and energy efficiency industries, and the public, the Board has considered the entire record within the context of the Act. In this proceeding, interested parties were given the opportunity to participate in the evaluation of these issues relative to the changing role of the electric and gas industries. Following issuance of this Order, the Board will continue to monitor how this climate develops, and to foster the development of this necessarily fluid process. The Board cannot overemphasize the need for a strong public policy with regard to establishing renewable supply-side programs in New Jersey, as well as the promotion of all energy efficiency and renewable energy technologies in our State.

The major elements of the CRA are program funding, program administration, and the program design itself. See N.J.S.A. 48:3-60(a)(3). In making our decision, the Board has considered two stipulations, filed by two groups of the parties, against the background of the full record. Here, the Board believes it has crafted a set of programs which draws from both of the settlements. In so doing, the Board is cognizant of the many areas of agreement between the two stipulations. At the same time, the Board recognizes that, while the stipulations share many areas of agreement, they do ultimately diverge into two different philosophical views of CRA. Essentially, the differences revolve around choices of program type and design for both energy efficiency programs and renewable energy, the appropriate level of funding to commit to these programs, and the administration structure that should be employed. The Board's choice of various elements from the two positions is fundamentally a discretionary decision within its jurisdiction. With this proceeding, the Board begins to achieve the long-range environmental goal of the Act to establish renewable energy programs that are indigenous to the State of New Jersey.

Facing drastic energy price escalation, the Board adopted regulations requiring electric and gas utilities to offer conservation, energy efficiency and load management programs, known collectively as Demand Side Management programs. N.J.A.C. 14:12-1.1 to 5.4. DSM programs consisted of "the management of customer demand for energy service through the implementation of cost-effective energy efficiency technologies, including installed conservation, load management and energy efficiency measures on and in the residential, commercial, industrial, institutional and governmental premises and facilities in this State," N.J.S.A. 48:3-51. The Board designed these rules to encourage cost-effective investment in Demand Side Management initiatives, while providing financial incentives to the utilities for the success of the program. Thus, each electric and gas utility developed its own DSM program, including programs to encourage high efficiency residential and commercial/industrial new construction, rebates on high efficiency HVAC[1] and motor equipment installed in homes and businesses, as well as payments to energy service companies to install energy efficiency measures that had guaranteed levels of energy savings. These programs led to the development of a robust energy efficiency market infrastructure, and new technologies and standards for high efficiency equipment in New Jersey. Each utility, pursuant to the DSM component in its rate, currently offers an array of programs under its own Board-approved DSM plans. These consist of both core programs and performance-based programs using either a standard offer or shared savings approach, with the exception of South Jersey Gas Company, which still offers programs under its Conservation and Load Management Plan. As energy policy evolved, the DSM market infrastructure has adapted to the changing environment. Furthermore, as the electric and gas industries are making the transition to a competitive market, the energy efficiency market must likewise make a transition guided by this Comprehensive Resource Analysis.

The Board begins with a discussion of the legislative goal that energy efficiency and renewable energy are to play an integral role in the energy policy of the State. The Act provides:

> Simultaneously with the starting date for the implementation of retail choice, the Board shall permit each electric public utility and gas public utility to recover some or all of the following costs through a societal benefits charge that shall be collected as a non-bypassable charge imposed on all electric public utility customers and gas public utility customers, as appropriate:
>
> . . . . .
>
> (3) The costs of demand side management programs that were approved by the Board pursuant to its demand side management regulations prior to April 30, 1997. For the purpose of establishing unbundled rates pursuant to section 4 of this act, the societal benefits charge shall be set to recover the same level of demand side management program costs as is being collected in bundled rates of the electric public utility on the effective date of this act. Within four months of the effective date of this act, and every four years thereafter, the Board shall initiate a proceeding and cause to be undertaken a comprehensive resource analysis of energy programs, and within eight months of initiating such proceeding and after notice, provision of the opportunity for public comment, and public hearing, the Board, in consultation with the Department of Environmental Protection, shall determine the appropriate level of funding for energy efficiency

[1] HVAC stands for heating, ventilating and air conditioning systems.

> and Class I renewable energy programs that provide environmental benefits above and beyond those provided by standard offer or similar programs in effect as of the effective date of this act, provided that the funding for such programs be no less than 50% of the total statewide amount being collected in public electric and gas utility rates for demand side management programs on the effective date of this act for an initial period of four years from the issuance of the first comprehensive resource analysis following the effective date of this act, and provided that 25% of this amount shall be used to provide funding for Class I renewable energy projects in this State. [N.J.S.A 48:3-60(a)(3)]

Again, the Act states that the Board shall permit public utilities to recover demand side management costs through a Societal Benefits Charge ("SBC") collected as a non-bypassable charge imposed on customers. In order to unbundle the SBC portion of the rate, the Board first had to determine the DSM collection level on February 9, 1999. The legislative intent was to establish the unbundled SBC rate so that collections would recover the same level of programs costs in bundled rates as of that date. Compliance with this portion of the Act took place in the Electric and Gas Unbundling Proceedings, and the SBC was established for each utility with the implementation of fully unbundled tariffs: unbundled electric tariffs were implemented in July and August 1999, while fully unbundled gas tariffs were implemented commencing in 2000. The SBC has several components; the relevant part to the CRA proceeding is that established to collect the demand side management costs.

Next, the Act requires the Board to initiate a proceeding to undertake a Comprehensive Resource Analysis of energy programs, which is being completed with this Order. Id. The Act requires an opportunity for public comment and a public hearing. Id. Evidentiary hearings were held on November 15, 16, 22, 23, 29, and 30, 1999, October 11, 2000, and November 1, 2000. Comments were accepted at the public hearing, which was held on January 10, 2001. The Legislature directed the Board to consult with the Department of Environmental Protection ("Department" or "DEP") to determine an appropriate level of funding for energy efficiency and renewable energy programs to provide environmental benefits in addition to those provided by the standard offer or similar programs in effect at the time of the Act's passage. Id. The Department has provided a report, and recommendations, which the Board has considered in its decision.

The Act directs the Board to provide that the funding for new energy efficiency and renewable energy programs be no less than 50% of the total amount collected statewide for all DSM programs as of the effective date of the Act, and that such funding should be set for an initial period of four years. The intent of this section in the Act is to enable determination of the funding level for DSM programs, as opposed to the establishment of the SBC rate. Unbundling the rates, although related, is completely separate from the issue of the funding level. In order to determine this funding level, the Board first had to establish the amount of collections. It is an important distinction to make in the interpretation of N.J.S.A. 48:3-60(a)(3), that several related, yet functionally distinct, requirements are contained therein. These collections must be calculated for a period of one full year in order to comply with the Act's implicit language that CRA should be based on the actual amount collected by the gas and electric utilities, and not merely a theoretical amount. To determine the actual collections, the applicable rate(s) in effect for the time period are multiplied by the utility's sales during that period. The most recent full year of data prior to February 9, 1999, the Act's effective date, was for 1998. Using the 1998 sales and the rates in effect to collect demand side management program costs during 1998, the Board has established

the actual collections as $215 million. Based on this fact, the Act would require the annual funding for the four years of the CRA program to be at least $107.5 million per year, or 50% of $215 million. In addition, the Act requires that 25% of that amount should be used to fund Class I renewable energy projects. Id. Accordingly, that amount of funding for renewables should be at least $26.875 million, with $80.625 million for energy efficiency projects. In short, this brief reference in the Act contains instructions for establishing the unbundled rate at which the utilities will continue to collect for DSM, energy efficiency and renewable energy programs for the four years of the transition plan, how to determine the minimum funding for new programs, and funding levels for the renewable energy versus energy efficiency programs.

Finally, the Act also requires the Board to determine, as a result of the Comprehensive Resource Analysis, the programs to be funded by the SBC, the level of cost recovery and performance incentives for old and new programs, and whether the recovery of DSM costs may be reduced or extended. Id. In making that determination, the Legislature directed the Board to take into consideration "existing market barriers and environmental benefits, with the objective of transforming markets, capturing lost opportunities, making energy services more affordable for low income customers and eliminating subsidies for programs that can be delivered in the marketplace without electric public utility and gas public utility customer funding." Id. After consideration of the entire record, and stipulations submitted by the parties culminating in this Order, the Board has completed these tasks.

Thus, in summary, the Board considers the fundamental issues of funding, administration and program design. The Board must first determine the amount of funding available for CRA. As the Act directs, the Board finds that the level of DSM program costs being collected as of the effective date of the Act, that is, February 9, 1999, to be $215 million. This determination is made by calculating the actual revenues collected by each electric and gas utility for the last full year. The Board finds that this year of establishing the program, including the interim funding of $15 million, as authorized by the Board Order of December 4, 2000, and as modified by the Board at its March 1, 2001 Agenda Meeting, constitutes the first year of the program.[2] Therefore, the Board determines that the minimum funding for 2001, as required by EDECA, is $107.5 million. However, the Board finds that it is appropriate to increase the first year's funding beyond the minimum to provide the maximum amount of funding while still mitigating rate impacts. Therefore, the funding for 2001 shall be $115 million, $119.326 million for 2002, and $124.126 million for 2003. In addition, in recognition of the delay in completing the Comprehensive Resource Analysis, the Board finds that $15 million shall be added to funding for the fourth year, as will be determined to be appropriate by the Board after the lifting of the utilities' rate caps in August 2003. The Board shall allocate the funding at a proportion of 75/25 between energy efficiency and renewable energy programs, respectively.

With regard to administration, the utilities shall manage administration of the energy efficiency and customer-sited renewable programs for one year, during which time the Board shall contract with a consultant to make recommendations pertaining to program administration for the remainder of the four-year period. After the one-year transition, the consultant will assist the Board in identifying an entity to act as independent statewide administrator ("ISA"), who will take on the responsibility of administering the customer-sited renewable energy program and evaluate the utility administration

[2] This amount was originally set at $10 million. At the Board's meeting of March 1, 2001, the Board determined to increase that amount to $15 million.

of the energy efficiency programs. During the utility administration of these programs, the Board shall implement strict reporting requirements on a quarterly basis to ensure proper CRA implementation. The Board shall administer the grid supply program(s) in consultation with the Department of Environmental Protection.

The program design for renewable energy programs shall consist of a buydown program for projects primarily designed to supply a customer's energy needs and a production credit for grid supply projects awarded on a competitive basis. The basic design for energy efficiency shall be market transformation consisting of various program strategies, which will address all market segments to some degree. These are essentially the programs as outlined in the Utility [illegible]

In addition to the seven utilities and the Division of the Ratepayer Advocate, motions to intervene were filed by Natural Resources Defense Council ("NRDC"); SESCO, Inc. ("SESCO"); American Wind Energy Association ("AWEA"); New Jersey Public Interest Intervenors ("NJPII"); Casino Group; Energy Photovoltaics, Inc. ("EPV"); GeoSolar, Inc. ("GeoSolar"); Honeywell DMC Services, Inc. ("HDMC"); Renewable Ventures, LLC ("RV"); Eastern Heating and Cooling Council, Inc. ("EHCC") and the Environmental Defense Fund ("EDF"). Jointly, the National Association of Energy Service Companies ("NAESCO"), the New Jersey Coalition of Energy Service Companies ("NJESCO"), and ONSITE SYCOM filed a motion to intervene. The ensuing Procedural Order, dated November 4, 1999, established tentative hearing dates, addressed motions to intervene and for pro hac vice admission,[3] and granted intervenor status to the above entities.[4] Finally, while allowing all intervenors the opportunity to litigate issues of concern, the Board urged parties with similar interests to work together.

Following a period of intensive discovery, a pre-hearing conference was conducted by the advising Deputy Attorney General on November 10, 1999. Evidentiary hearings were held before Commissioner Frederick F. Butler on November 15, 16, 22, 23, 29 and 30, 1999 for testimony and cross-examination by the parties on issues identified by the Board.

More specifically, direct and/or rebuttal or surrebuttal testimony was filed by Nathaniel Greene on behalf of NRDC addressing the issues of the appropriate level of funding for new investments in energy efficiency and renewable technologies, types of energy efficiency programs that should be funded by the SBC, types of renewable energy programs that should be funded by the SBC, and criteria for administration of such programs. Dr. David A. Nichols testified on behalf of DRA addressing renewable energy, energy efficiency, universal service as it relates to energy efficiency, and rebuttal on the issue of free riders. Michael Marks testified on behalf of NJNG, Elizabethtown and SJG, proposing a CRA program for the gas utilities of New Jersey and rebuttal. Edward A. Smeloff testified on behalf of American Wind Energy Association, Astropower, Inc. BP Solarex, Energy Photovoltaics, Inc., GeoSolar, Inc., H Power Corp., Mid-Atlantic Solar Energy Industries Association, New Jersey Public Interest Intervenors, Renewable Ventures LLC, and Siemens Solar Industries, recommending a renewable energy program to foster the development of a robust renewable energy industry in New Jersey, rebuttal on utility company capability to administer renewable programs, and the sufficiency of renewable energy program costs to satisfy the legislative intent of the Act. Christopher W. Siebens testified on behalf of GPU seeking to clarify appropriate initial funding levels, administration of energy efficiency and renewable programs, and program design. Richard M. Esteves testified on behalf of SESCO, Inc. addressing requirements of Section 12 of the Act and the many questions raised by the Board in its "Order Establishing Procedures," dated June 17, 1999, and emphasizing five key points for the Board to establish a SBC to assure cost-effective, and equitably distributed benefits – environmental and economic – for New Jersey's families and businesses. Natalie Patasaw testified on behalf of the Environmental Defense Fund, discussing the options available for increasing the supply of new renewable energy technologies and recommending policies and methodologies that are responsible, cost-effective, administratively efficient, supportive of private market development, and that enable the transition

[3] The Board granted pro hac vice admission to James T.B. Tripp of EDF, Dale S. Bryk of NRDC, David R. Wooley of AWEA, Douglas H. Ward of RV and John L. Carley of RECO.

[4] At its agenda meeting of November 24, 1999, the Board also granted intervenor status to Nextek Power Systems Inc. EHCC was granted participant status.

to a self-sustaining renewable energy industry. Dr. Bruce Bailey testified on behalf of the American Wind Energy Association, discussing the characteristics of wind energy relevant to this case. Kevin C. Jones testified on behalf of Rockland Electric Company, addressing issues related to the Energy Efficiency and Renewable Resource Utilization Plan, including administration and implementation. Frank P. Marino also testified on behalf of RECO, addressing RECO's position on the implementation of energy efficiency and renewable energy programs and the level of recovery for such programs through the SBC as currently included in rates, and to respond to issues on energy efficiency and renewable energy funding requirements, RECO's compliance with such requirements, uniform SBC components, and provision of energy efficiency services by utility affiliates. Walter L. Davis testified on behalf of Conectiv, setting forth the Company's response to the BPU Order, dated June 17, 1999 with regard to CRA. Gerald W. Schirra testified on behalf of Public Service Electric & Gas Company, supporting all aspects of the company's filing prepared and submitted in response to the Board's Order. William G. Rosenberg testified on behalf of Renewable Ventures LLC, discussing the shortfall between mandated demand under Renewable Portfolio Standards and current supply of Class I renewable energy in New Jersey and across the Pennsylvania, Jersey, Maryland Interconnection, L.L.C. ("PJM"), as well as funding to supply-side projects to make up the supply shortfall, and funding of Class I renewable projects. Donald Gilligan testified on behalf of National Association of Energy Service Companies, the New Jersey Coalition of Energy Service Companies, and ONSITE SYCOM, setting forth the immediate concerns of NAESCO, NJESCO and ONSITE SYCOM relating to the CRA. John H. Manning, of Honeywell DMC Services, testified addressing specific issues concerning energy efficiency programs and funding.

On what was scheduled to be the final day of hearing, a briefing schedule was established. Initial briefs were due December 21, 1999 and reply briefs were due January 10, 2000. During the hearings, various motions were ruled on by Commissioner Butler, whose rulings are HEREBY AFFIRMED by the Board, essentially for the reasons set forth orally by Commissioner Butler.

Throughout the course of the proceeding, the parties engaged in settlement negotiations in an attempt to reach a consensus on the terms of an agreement and stipulation for submittal to the Board. At its meeting on February 2, 2000, the Board established a deadline of February 9, 2000, by which any stipulations would have to be submitted to the Board for consideration, and a deadline of February 16, 2000 for any parties to submit comments on any stipulation.

As a result of these efforts, on February 9, 2000, the parties submitted two different settlement agreements for the Board's consideration. Six of the utilities, Elizabethtown, NJNG, PSE&G, SJG, GPU Energy, Conectiv, and NRDC jointly filed a Stipulation ("Utilities/NRDC Stipulation"), which was additionally signed by EDF, American Wind Energy Association, BP Solarex, Renewable Ventures, and Eastern Heating and Cooling Council.[5] The other Stipulation was jointly filed by the DRA, NJPII, SESCO, NAESCO, NJESCO, ONSITE SYCOM, Astropower, Inc., EPV, GeoSolar, Inc., GreenMountain.com, H Power Corporation, Mid-Atlantic Solar Energy Industries Associates, Siemens Solar Industries and BP Solarex ("DRA Stipulation").[6] Comments on the stipulations were received from NRDC, EDF, RECO, jointly from NAESCO, NJESCO, and ONSITE SYCOM, NJPII, SESCO, the DRA, and jointly from the six signatory utilities. Before concluding this proceeding, pursuant to Order dated August 16, 2000, the Board directed the utilities and DRA to

[4] RECO did not join this stipulation.
[5] Not all signatories to the stipulation were formal intervenors in the proceeding.

supplement their filings with specific calculations as to the ratemaking impact of the stipulations with the opportunity to comment. While the parties to the Utilities/NRDC Stipulation filed these calculations, no such information was received from the parties to the DRA Stipulation. Two additional days of evidentiary hearings were held on October 11, 2000 and November 1, 2000. As in the initial round of hearings, testimony and cross-examination by the parties on the issue of rate impacts was presented.

On October 11, 2000, Commissioner Butler heard testimony from panels representing both stipulations on the administrative costs associated with the choice of programs and budget, and their effect on rates. Specifically, Nathaniel Greene of NRDC, Frederick Lynk from PSE&G, Robert Gallo of NJNG, Christopher Siebens of GPU and Walter Davis of Conectiv, testified in connection with the Utilities/NRDC Stipulation and Donald Gilligan of NAESCO, NJESCO, ONSITE SYCOM, Dr. David Nichols of DRA, and Lyle Rawlings of Mid-Atlantic Solar Energy Association testified in connection with the DRA Stipulation.

On the second day of hearing, November 1, 2000, the following witnesses testified as to the rate impact of the respective stipulations: Roger Pederson of Conectiv, Christopher Siebens of GPU, Kevin Moss of NJNG, Tom Kaufmann of Elizabethtown, Gary Dean of SJG, Frank P. Marino of RECO, and Gerald W. Schirra of PSE&G, presented testimony as a panel as did, S. Lynn Sutcliffe of NAESCO, Donald Gilligan of NAESCO and SESCO, and David A. Nichols of DRA. Also on the final day of hearing, DRA moved to continue the supplementary hearing. Commissioner Butler gave the parties the opportunity to brief the issue.

As in the first round of hearings, during these hearings, various motions were ruled on by Commissioner Butler, whose rulings are HEREBY AFFIRMED by the entire Board, essentially for the reasons expressed by Commissioner Butler on the record.

At its meeting of December 6, 2000, the Board addressed various outstanding motions, the rulings on which we now memorialize herein. The Board granted in part and denied in part a motion to reopen and supplement the record with the PSE&G website and DEP materials submitted to the Board. More specifically, NAESCO and SESCO urged admission into evidence of the PSE&G website as both relevant evidence itself and to impeach the testimony of PSE&G witness Gerald Schirra. Mr. Schirra had denied that PSE&G had performed analysis to quantify environmental benefits derived from PSE&G Demand Side Management programs. PSE&G's website, however, stated, "benefits to the environment have been dramatic." In opposition, PSE&G argued that the website information could have been discovered sooner and that the website material does not in fact impeach the witness.

The Board HEREBY GRANTS the motion to reopen and supplement the record with the website by taking judicial notice of the website. Further, the Board has taken notice of the arguments submitted both in support of and in opposition to the motion so that the material can be given appropriate weight.

In addition, NAESCO and SESCO sought disclosure of the DEP materials submitted to the Board pursuant to its consultative role established by statute. Specifically, pursuant to N.J.S.A. 48:3-60(a)(3), the Board must initiate a proceeding and undertake a Comprehensive Resource Analysis of energy programs and after notice, the opportunity for public comment and public hearing, the Board, "in consultation with" the DEP is to determine the appropriate level of funding for energy

efficiency and Class I renewable energy programs. NAESCO and SESCO, supported by the Ratepayer Advocate, maintained that because the statute requires the consultation, it is a matter of public information and should be made a part of the record. They further argue that the parties are entitled to consider the materials before the Board in making its decision and to have the opportunity to comment thereon.

The Board is cognizant of the direction by the New Jersey courts that factual materials relied upon by administrative agencies be made public. The Supreme Court of New Jersey in In re of Liq. of Integrity Ins. Co., 165 N.J. 75, 88 (2000), recently confirmed that its intent in McClain v. College Hosp., 99 N.J. 346 (1985), was to establish a qualified privilege for government deliberative process materials. The state agency must show that the documents to be shielded are "pre-decisional and deliberative in nature containing opinions, recommendations, or advice about agency policies." Integrity, supra, at 88. Purely factual material is not to be shielded. Id. at 85.

Accordingly, the Board HEREBY GRANTS IN PART and DENIES IN PART the motion for release of the DEP reports. As determined orally, and subsequently confirmed by letter to the parties, dated December 7, 2000, the Board directed that these materials be redacted so as to present to the parties the factual information submitted to the Board by the Department. The Board gave the parties until December 15, 2000 to file any further comments with respect to this matter due to these materials of the Department. The DRA and NJPII did submit comments, which are considered, where appropriate, in the findings of this order.[7]

Blossom A. Peretz, Esq., Ratepayer Advocate, by letter dated December 15, 2000, submitted comments on behalf of the DRA relating to the redacted DEP report that was delivered to the BPU under cover letter dated June 22, 2000. The DRA requested that it be provided an un-redacted version of the June 22, 2000 DEP report and a copy of the January 21, 2000 cover letter addressed to President Tate from DEP Commissioner Robert Shinn, and any other reports by the NJDEP to the BPU pertaining to this matter. Moreover, the DRA reserves its legal right to challenge the redaction of these documents. Ms. Peretz argues that the DRA's ability to comment on the report has been constrained.

With that background, there are many aspects of the DEP report with which the DRA is in agreement. Specifically, Ms. Peretz agrees with the DEP's statement that the level of funding for energy efficiency and renewable energy programs determines environmental benefits. Furthermore, she quotes the report stating that the greatest environmental benefit occurs by displacing a ton of conventionally generated power, first by power generated by renewable energy technologies, and then by using that power efficiently.

Although there are points of agreement, the DRA disagrees with the DEP report in several areas. In particular, Ms. Peretz asserts that the DEP report incorrectly states that only 11% of energy efficiency environmental benefits are derived from the residential sector. Ms. Peretz argues that the DEP ignored many of the measures identified in both stipulations and urges the Board to

[7] Comments submitted by Mr. Potter were received late but were nonetheless reviewed. In essence, after analyzing the redacted DEP report, Mr. Potter argues that the DRA Stipulation is superior because consumers pay only for demonstrated results which conserve energy, reduce costs and rates and provide environmental benefits.

maintain funding at a level, which does not fall below that provided for in either stipulation. Ms. Peretz asserts that equity should be taken into consideration. The DRA also points out the differences between the Utility/NRDC and DRA Stipulations in that the DRA Stipulation has "pay-for-savings" programs that are particularly suited to near-term retrofit projects that accrue environmental benefits rapidly.

There are differences in the renewable energy programs that also must be addressed. The DRA Stipulation gives gas fired fuel cells a lower incentive than renewable energy fuel cells, should the Board decide to include such fuel cells in the renewable energy program. Ms. Peretz argues that the funding of fuel cells contradicts the goals of this program, which is intended to promote the growth of renewable energy technologies, not fossil fuels. Additionally, it is inappropriate to require electric ratepayers to provide funding for a technology that promotes natural gas consumption.

The DRA disagrees with the DEP's contention that no size limit is needed on renewable resources and asserts that technologies that are near market and relatively lower in cost may not need the subsidized funding. Ms. Peretz asserts that the programs should focus on emerging technologies that are generally smaller in size and not market-ready. The DEP believes that small landfill gas projects are not near market and thus may need CRA support. However, the DRA states that the Renewable Portfolio Standards ("RPS") will provide the incentive needed to foster these smaller projects.[8] Lastly, Ms. Peretz points out that the Utilities/NRDC Stipulation does not include landfill gas as an energy project.

By letter, dated December 14, 2000, John G. Williams, of Pace Mid-Atlantic Energy Project, Inc., submitted comments on behalf of New Jersey Public Interest Intervenors on the DEP report that was redacted. Pointing to the statutory directive on DEP's role, NJPII asserts that the DEP documents within its report do not provide the BPU with any basis for making such a determination, because the report did not appropriately ascertain the level of environmental benefits associated with the various renewable energy and energy efficiency programs, specifically standard offer programs. Instead, NJPII maintains that DEP only compared the two competing stipulations, using the invalid assumptions that the funds are distributed to energy efficiency and renewable energy in a similar manner, and that the types of programs and technologies funded produce the same level of energy reductions. Moreover, NJPII agrees that DEP made no calculations for avoided air emissions for such pollutants as CO_2, NO_x, SO_2, particulates, Hg, and VOC's. The DEP simply used dollars spent on each program as a proxy for determining environmental benefits.

Conversely, NJPII had previously submitted a methodology for calculating environmental benefits that was not used by either the BPU or the DEP. NJPII argues that only one program from the Utilities/NRDC Stipulation

NJPII then goes on to state its recommendations, which are similar to those outlined in the PPA

the Board concedes a certain superficial attractiveness to wishing to include in this record a broad scope of materials, it is also important to conclude matters.

Finally, on January 10, 2001, following notice, a public hearing was held at the Board's Newark offices. The purpose of the public hearing was to allow comments, either oral or written, on these proceedings, without cross-examination, from the public, the utilities or any other parties who have been participants in this proceeding.

All filings, transcripts, and stipulations were made available for review prior to the public hearing. Furthermore, a notice of the public hearing was published in various newspapers throughout the state on December 26, 2000. The following people presented comments: Robert Shinn, Commissioner of the Department of Environmental Protection; Dale Bryk on behalf of NRDC; William Potter on behalf of NAESCO and SESCO, Inc.; Todd Foley on behalf of BP Solarex; Ron Kamen on behalf of a consortium of environmentally responsible companies, including Phillips Lighting, Calmac Manufacturing Corporation, B&B Engineering, Renewal Realty, various electrical distribution companies and carpet recycling companies; Thomas Leyden on behalf of Power Lite Corporation; Mark MacCracken of Calmac Engineering; Donald Gilligan on behalf of NAESCO; John Leibowitz; Ed Smeloff of Pace Law School Energy Project; Blossom Peretz of the Ratepayer Advocate; Dolores Phillips on behalf of Government Relations for Energy Photovotaics ("GREP"); Natalie Patasaw on behalf of EDF; John Cooper on behalf of Meri Star Hotels; and Lyle Rawlings on behalf of the Mid-Atlantic Solar Energy Industries Association and the New Jersey Solar Industry.

Robert Shinn, Commissioner of the Department of Environmental Protection, testified that energy is the single largest source of air pollutant emissions. He notes that the Act sought to address those negative impacts while advancing the Governor's goal that New Jersey be a self-sustainable state in energy. TR- 1/10/01, at 5. Commissioner Shinn urges use of the New Jersey Greenhouse Gas Action Plan to establish the environmental goals and objectives for the energy efficiency and renewable energy programs in a flexible manner and through on-going consultation by the DEP with the Board. TR-1/10/01, at 9. Commissioner Shinn supports the 75/25 percent split between energy efficiency and renewable energy programs. TR- 1/10/01, at 13.

Finally, regarding administration of the programs, Commissioner Shinn states that the Board, in consultation with the DEP, has the required expertise to insure both an economically efficient and operationally sound competitive energy market. TR-1/10/01, at 17-18. He recommends that the BPU, in consultation with the DEP, administer the grid supply Class I renewable energy programs through a competitive bid process. TR-1/10/01, at 18. He also stated that the utilities, on an interim basis, should administer the energy efficiency and customer sited Class I renewable energy programs with measurable and achievable environmental goals and targets, on a statewide joint and coordinated approach, with oversight by the Board, and in consultation with the DEP. TR-1/10/01, at 18.

Dale Bryk from the NRDC spoke in support of the Utilities/NRDC Stipulation. She also spoke on behalf of Honeywell DMC with regard to administration and program design and Rockland Electric. TR-1/10/01, at 24 -25. Ms. Bryk notes that the energy savings from energy efficiency and renewable energy programs can insulate customers against high energy prices as well as offset the need for more generation facilities and transmission lines. TR-1/10/01, at 26.

She also discusses the resulting environmental and cost benefits of the Utilities/NRDC Stipulation. TR-1/10/01, at 27. On renewable energy program design, Ms Bryk notes that there is broad agreement for customer rebate programs for the installation of solar panels, fuel cells or wind turbines and for large-scale renewable energy programs that supply power to individual customers through the grid. TR-1/10/01, at 27-28. Moreover, she supports an auction program and a market development program designed for maximum projects at the lowest prices. TR- 1/10/01, at 28.

Ms. Bryk points to the funding similarities in both pending stipulations. Each stipulation supports increases in funding for new programs over prior years and guarantees that higher levels of funding occur for eight years. TR-1/10/01, at 30. On administration, Ms. Bryk points out that all parties agree with the concept of a statewide administrator to oversee the grid-supply renewable program and that most parties agree, that on an interim basis, utilities should continue to administer the energy efficiency programs. TR-1/10/01, at 30. Ms. Bryk supports utility administration of these programs under the supervision of the BPU. TR-1/10/01, at 31.

R. William Potter, representing NAESCO and SESCO, Inc., supports the DRA Stipulation because it provides for the statutory minimum level of funding of $128 million and is dedicated to "pay for results." TR- 1/10/01, at 111. Mr. Potter argues that the Utilities/NRDC Stipulation focuses on programs related to the production of studies, market reviews, baseline assessments, evaluations and educational efforts which do not result in energy savings benefits, and which are similar to the core programs under the DSM regulations, which were not subject to any cost benefit test. TR-1/10/01, at 114. Mr. Potter urges a compromise between the two approaches: $64 million for programs as described in the DRA Stipulation with the other half dedicated to the programs proposed by the Utilities/NRDC Stipulation. TR- 1/10/01, at 116.

At the public hearing, Todd Foley, representing BP Solarex, stresses the salutary attributes and importance of solar energy. Mr. Foley expresses support for solar programs, both a customer sited rebate program, and a grid supply program, TR- 1/10/01, at 132-133, as well as establishment of effective metering and interconnection standards with these programs. TR- 1/10/01, at 134-135.

Ron Kamen, representing a consortium of environmentally responsible companies, stresses the importance of a wide variety of energy conversion technologies in the plan that is adopted by the Board. TR- 1/10/01, at 140. He also supports a program that is implemented statewide rather than different systems administered by each of the seven utilities.

Thomas Leyden, representing Power Lite Corporation, urges prompt implementation of the CRA program, TR- 1/10/01, at 144. He urges rejection of the Utilities/NRDC Stipulation because there is an inherent conflict of interest between the utilities and solar projects. TR- 1/10/01, at 147-148. He also notes that the private sector would be better at promoting renewable energy systems. TR-1/10/01, at 148.

Mark MacCracken, CEO of Calmac Manufacturing, represented the Air-Conditioning and Refrigeration Institute, Thermal Energy Storage Section. TR- 1/10/01, at 153-154. Mr. MacCracken expresses the importance of energy storage technology and its energy savings potential, with concomitant savings and environmental benefits. TR – 1/10/01 at 154, 159.

Donald Gilligan, representing NAESCO, in support of the DRA Stipulation, requested that the Board take judicial notice of the proceedings underway in California because one of the causes of

California's problem was the shift away from energy acquisition programs to market transition programs. TR- 1/10/01, at 160, 162, 163. He notes that this essentially mirrors the difference between the Utilities/NRDC Stipulation, which promotes market transition programs, and the DRA Stipulation, which encourages resource acquisition programs and pay for savings/performance programs. TR-1/10/01, at 163-164.

John Leibowitz, an independent energy analyst, advocates for cogeneration and combined heating and power. TR- 1/10/01, at 172. Mr. Leibowitz believes that all barriers should be removed for combined heat and power plants so they may be locally developed. TR- 1/10/01, at 173.

Ed Smeloff, Executive Director of the Pace Law School Energy Project, testifies that energy efficiency programs help reduce the retail price, consumers pay for electricity and thus effect the rate impacts on consumers once the retail price caps are lifted in 2003. TR-1/10/01, at 92. Mr. Smeloff argues that as energy efficiency reduces demand, the price for electricity drops and that the reduction in demand not only benefits the consumer, but lowering demand during peak hours benefits all ratepayers in the state. Mr. Smeloff argues that this value is determinable. TR-1/10/01, at 95. Accordingly, he urges a resource acquisition design for energy efficiency programs as opposed to the market transformation design which does not produce measured results. TR-1/10/01, at 100 - 103.

The Director for the Division of the Ratepayer Advocate, Blossom Peretz, provided remarks in support of the DRA Stipulation. TR- 1/10/01, at 36, 41. Ms. Peretz urges establishment of an independent statewide administrator to handle the funding for both energy efficiency and renewable energy projects, as well as placing the funds in a single renewable trust fund. TR-1/10/01 at 35-36. Ms. Peretz counsels against recovery of lost revenues. TR- 1/10/01 at 40. Ms. Peretz supports the allocation of funds in the Board's Interim Order between energy efficiency and renewable energy programs under an independent administrator. TR- 1/10/01 at 41, 39.

On behalf of, and as Director of GREP, Dolores Phillips testified. TR- 1/10/01, at 46. Ms. Phillips recommends that the Office of Sustainability at the NJ Department of Commerce or the Board administer the renewable energy programs. TR- 1/10/01, at 49. She also questions utility administration of the customer sited energy efficiency and renewable energy programs, TR-1/10/01, at 50, 51. Finally, she expresses disappointment in the CRA process. TR- 1/10/01, at 53.

Natalie Patasaw, on behalf of EDF, supports quick implementation of the CRA, which fosters competition in the energy efficiency, renewable energy, and conventional electric generation industries. TR- 1/10/01, at 55. Ms. Patasaw further supports renewable energy coupled with increased energy efficiency programs which promote building retrofits, new construction, better and smarter appliances and industrial innovation. TR- 1/10/01, at 58, 59. Finally, Ms. Patasaw supports a statewide administrator for grid supply renewable energy programs and, initially, temporary utility administration for no more than a year with ultimate responsibility going to an independent statewide entity. TR- 1/10/01, at 60.

John Cooper from Meri Star Hotels supports funding for Geo Thermal/Geo Exchange technology for the underfunded commercial sector because of its tremendous environmental track record. TR-1/10/01, at 63.

Lyle Rawlings, representing the solar industry for New Jersey and the mid-Atlantic region, expresses concern with the conflict of interest if the energy efficiency and customer sited renewable programs are administered by the utilities. TR- 1/10/01, at 67. Further, Mr. Rawlings is concerned that a significant portion of the funding goes toward research and development, training, awareness and outreach, market facilitation, market analysis and target marketing, and not enough is going toward the actual renewable projects themselves. TR- 1/10/01, at 71. He also argues for no more than 5% of the funding to go for administrative costs, and no more than 15% for research and development and education training. TR- 1/10/01, at 75, 76. Mr. Rawlings also calls for consideration of the situation in California.

III. COMPREHENSIVE RESOURCE ANALYSIS

As noted above, following the parties' initial filing of positions and testimony, Commissioner Butler presided over six days of evidentiary hearings. Thereafter, the parties submitted briefs and reply briefs on the issues. Key elements of the briefed positions of various parties with regard to certain specific issues of relevance are summarized hereinbelow, by issue. In addition, as required by N.J.S.A. 48:3-60(a)(3), the DEP conducted an analysis for this proceeding in connection with energy efficiency and renewable energy funding. Accordingly, the Department undertook to evaluate the testimony, information and data, both written and oral, submitted at the evidentiary hearings. The Department made recommendations to the Board to implement the societal benefits charge funding to aid in meeting the legislative intent of developing energy efficiency and renewable energy programs that provide environmental benefits above and beyond those currently in place. The Department considered the environmental benefits of various program funding levels, program administration, and types of programs for energy efficiency and Class I renewable energy. Following that analysis, the Department also reviewed the stipulations and submitted comments to the Board.

A. Funding

1. Annual amount

The DRA recommends that the minimum annual amount for renewable energy and energy efficiency programs be $128.36 million. DRA Initial Brief, at 7. The DRA argues that the Act requires the funding to be 50% of the amount that was being collected in electric and gas utility rates on February 9, 1999, which was $256,720,175. Id. DRA states that 25% of the $128.36 million, or $32.1 million, should be allocated to Class 1 renewable energy projects and the remaining 75%, 96.3 million, to energy efficiency projects. DRA Initial Brief, at 11.

The DRA claims the utilities' efforts, except PSE&G's, to find statutory support for their interpretation, fail. DRA Initial Brief, at 9. Instead, DRA argues that the impacts after the rate freeze period should not affect the Board's decision on the level of funding because the programs funded will reduce customers' consumption thereby negating or reducing the impacts of increased rates. DRA Reply Brief, at 12.

EDF defers on the issue of overall funding to Pace Energy Project, NRDC and the DRA, but asserts that the funding level for renewable projects is critical and the BPU should set minimum levels for all eight years. EDF Initial Brief, at 9. EDF urges an overall initial minimum per year funding level of $115 million, but asserts that the quality, as well as the quantity of renewable investments, will determine success. Id.

NJPII interprets the Act so as to put the combined funds at a base of $128 million (50% of $256 million) annually. Initial Testimony/Smeloff, at 23. NJPII bases this on several references in the Act to the total statewide amount being collected in rates. Id. NJPII points out that the legislation does not suggest adjustments for lost revenues. Initial Testimony/Smeloff, at 24. NJPII provides a detailed analysis of the legislative language, concluding that the retirement of past standard offer or similar commitments are to be included in the initial calculation of the total statewide amount. Id.

ESCO intervenors urge rejection of the utilities' interpretation of the Act. ESCO Intervenors Joint Initial Brief, at 10. Instead, they argue that the correct interpretation of the Act is that the 50% of collections is a floor not a ceiling. ESCO Intervenors Joint Initial Brief, at 14. The Board should set the funding level by February 3, 2000. ESCO Intervenors Joint Initial Brief, at 15. They argue that the utilities' arguments lack a reasonable statutory foundation and rely on an incorrect understanding of legislative intent. ESCO Intervenors Joint Initial Brief, at 22.

Conectiv asserts that the Act calls for a gradual increase in funding up to a minimum of $140,000,000 in the eighth year for energy efficiency and renewable energy, as well as program costs that it has proposed as the appropriate funding level. Conectiv Brief, at 5. Conectiv proposes maintaining its level of spending at what is included in its unbundled rates, in response to the dichotomy between the four-year rate cap and the issues of funding and recovery of energy efficiency and renewable energy programs. Conectiv Brief, at 6. Conectiv also notes that the witnesses for both NJPII and the DRA recognize a need for balancing the rate impact with the desire to spend more, as evidenced by witnesses Dr. Nichols' and Mr. Smeloff's support for phasing in the increase in rates for some utility customers to equalize spending statewide. Conectiv Brief, at 6, 7.

Conectiv argues that it, along with all the utilities, collected $131,890,975 for actual programs and the amount collected for other costs was an additional $124,829,200. Conectiv Brief, at 7, 8. Conectiv argues that a statewide collection level of $256 million should not be used as the basis for a decision, and that the record contains uncontroverted evidence that the statewide amount is $131,890,975. Conectiv Brief, at 8. Conectiv further maintains that the $256 million includes recovery of deferred unrecovered balances and other monies, which do not fall into the category of Demand Side Management programs, and the Act is clear that these are not part of the calculation of minimum funding. Conectiv Brief, at 9. Conectiv relies on language in the Act, which contemplates additional funds becoming available and being added to the funding available. Id. Finally, Conectiv asserts that the Board's determination of the minimum funding cannot be arbitrary, but based on record evidence. Id. Because Conectiv has no pre-existing funding commitments, it asserts it is able to dedicate the full recovery amount of $4.8 million to new programs. Conectiv Brief, at 10. Conectiv urges that the minimum statewide funding level for new programs be $66 million based on the uncontroverted record in evidence. Conectiv Brief, at 12.

GPU points to the plain language in the Act as the basis for funding and argues that the interpretation and application thereof is a legal matter for the Board as the trier of law. GPU Brief, at 6. GPU asserts that no witness who testified on interpretation of the Act regarding the initial funding level was qualified as a legal expert in this proceeding and was, therefore not entitled to be given any weight by the Board. Id. GPU notes that the initial statewide funding level based on the

Act's plain language, is $65 million.[9] GPU Brief, at 7. GPU bases this on the reference in the Act to Demand Side Management program costs, which it asserts are clearly separate from other Demand Side Management costs as defined in the Board's existing DSM regulations, N.J.A.C. 14:12-4.1(c). Id. Additionally, GPU asserts that its Board-approved rider, Demand Side Factor, defines the separate costs being collected through the SBC, which are program costs, lost revenues, performance incentives and a reconciliation adjustment. GPU Brief, at 7, 8. Additionally, GPU asserts that the Board articulated in its June 17, 1999 CRA Order that recovery of both direct DSM costs and indirect DSM costs are provided for in the DSM regulations and that this distinction was also recognized by the NJPII witness. GPU Brief, at 8. GPU argues that the reference to program costs in the Act, rather than all DSM costs is significant and clearly indicates that the initial program funding should be based on the amount of program costs being collected from all of the utilities of $131 million, and therefore the level for new programs would be a minimum of $65 million. GPU Brief, at 9.

GPU further argues that because of the State's policy to lower rates, $65 million is the appropriate level of funding because any number above that would potentially increase rates. GPU Brief, at 6. GPU asserts that witnesses for NRDC, NJPII and DRA agreed during cross-examination that one of the primary purposes of the Act was to decrease electric rates, yet they proposed that the new program funding be established at $128 million. GPU Brief, at 10.

GPU observes that the DRA's witness, Dr. David Nichols, acknowledged that electric utility rates cannot be increased, and that due to deferred balances during the four-year rate caps, future rate changes might result from its funding proposal. Additionally, GPU asserts that Mr. Smeloff, on behalf of the joint filers, acknowledged that deferrals might accrue as a result of the DRA's funding proposal under the rate cap, and the NRDC's Mr. Greene stated that the impact of his proposal on deferrals would have less impact than they would if the Utilities were not collecting SBC funds at all. GPU Brief, at 11. GPU asserts that none of these witnesses provided any documented support nor performed any analysis of the impact of their funding proposals on the deferred balance. Id.

Christopher Siebens of GPU testified that if NRDC's proposal were adopted, the result would be an additional $80 million plus interest to GPU's deferred balance at the end of the four years. GPU Brief, at 12.

GPU finally asserts that it collected $23 million for DSM programs resulting in a 50% spending level of $11.5 million, but that its proportionate share is $15.5 million. GPU Brief, at 16. However, it proposes a level of $19 million. Id. In its May 24, 1999 Summary Order, the Board approved any DSM over recoveries which accrue to be applied to the Freehold Buyout Costs during the first four years of competition.[10] Id. GPU asserts that several parties claim this is inconsistent with the Act. However, Mr. Siebens asserted that these funds belong to customers and are benefiting customers by limiting the accrual of deferrals at the conclusion of the four-year period. Id.

GPU states that other parties have broadly interpreted the Act regarding the initial level of funding

[9] The reason for the appearance of both $65 million and $66 million is that the actual figure is $65.5 million, and in one instance, the figure was rounded up, while in other instances, it is rounded down.

[10] The Board has previously approved the GPU April 14, 1999 stipulation with modifications. The recovery of the buyout costs for the Freehold Cogeneration Contract were to be offset by any DSM over recoveries as set forth in the stipulation.

to further their own economic interests or those of their supporters. GPU Reply Brief, at 2. GPU notes that several parties assume the amounts being collected in rates is the same as the amount being collected for DSM programs, and that assumption is erroneous as these collections are used also for indirect program costs, such as recovery of amortized past commitments. Id.

As to NJPII's argument that GPU's interpretation of the Act regarding overall funding is inconsistent with its calculation of budgets for new programs, GPU responds that it is consistent because the initial funding minimum is based on 50% of SBC collections without lost revenues, incentives or past commitments, as is its budget for new programs. GPU Reply Brief, at 4. GPU asserts that the DRA proposal to double spending during the rate cap period

NRDC asserts that the Act requires the Board to establish minimum funding for new energy efficiency and renewable energy investments of no less than 50% of the amount currently collected in rates for all costs associated with demand side management and energy efficiency, or $128 million. Initial Testimony/Greene, at 2, 3. NRDC asserts that the Board should not permit the utilities to use funds collected through the SBC for costs other than those specified in Section 12, such as the proposal to pay off a NUG contract.[12] Initial Testimony/Greene, at 7.

2. Allocation between gas & electric

DRA believes that gas ratepayers should not pay for Class I renewable energy projects and would have electric company ratepayers pay the full $32.1 million. DRA Initial Brief, at 11. However, DRA recommends that the 75% or $96.3 million for energy efficiency projects be collected from gas and electric ratepayers in the same proportion as 1998 gas and electric gross revenues from sales. DRA Initial Brief, at 12. DRA asserts that electric revenues were 77% of the total so that $74.2 million would be collected from electric ratepayers and 23%, or $22.1 million, from gas ratepayers. RA-23, Exhibit DN-3. DRA Initial Brief, at 12. As a result of this allocation, electric ratepayers will need to pay an annual total of $106.2 million, while gas ratepayers would only pay $22.1 million. DRA Initial Brief, at 12.

Regarding the allocation of funding, GPU asserts that none of the intervenors have proposed an equitable distribution of funding, and that parity should be a long term goal based on consistent new program rates per therm/kilowatt and the accrual of deferred balances should not be based on

in rates are the same as the amounts being collected for DSM programs. Id. GPU supports its interpretation of the Act by stating "It is axiomatic that the meaning of a particular phrase or provision of a statute is to be determined in the context of the whole statute." Davis v. Heil, 132 N.J. Super. 283, 294 (App. Div.), aff'd 68 N.J. 423 (1975). Id. GPU disagrees with NJPII's argument that GPU's interpretation of the Act regarding overall funding is not consistent with its calculation of budgets for new programs. GPU Reply Brief, at 4. GPU asserts that it is consistent, because the initial funding minimum, as well as its budget for new programs, is based on 50% of SBC collections without lost revenues, incentives or past commitments. Id.

PSE&G believes it is first necessary to determine the allocation between electric and gas utilities and then within that, the allocation to each utility. PSE&G Initial Brief, at 4. PSE&G asserts that it be first "...done as a pro ration based on total statewide electric utility non-supply related revenues and total statewide gas utility non-supply related revenues." Id. PSE&G further asserts that the electric utilities' allocation should be calculated on the applicable electric system output and the gas utilities on the applicable gas send out. PSE&G Initial Brief, at 5.

This, PSE&G asserts, should result in parity, including all program costs in the spending rate among all electric utilities and among all gas utilities. Id. PSE&G asserts that these program costs must include current energy efficiency and renewable energy program spending including Standard Offer, but not include lost revenue recovery or recovery of prior deferred balances. Id. PSE&G asserts that parity is a major issue and provides Exhibits PSE&G-CRA 5 & 6 to demonstrate the disparity, and show that PSE&G is spending at a significantly higher rate than any other utility. Id.

Regarding the DRA's argument that renewable energy programs should be paid for entirely by electric ratepayers, PSE&G argues that the legislation envisions no such division of funding responsibility. PSE&G Initial Brief, at 6. PSE&G asserts that it is fair for gas ratepayers to participate in funding renewable programs because the potential benefits, such as clean air, do not benefit electric ratepayers alone. Id.

3. Parity

NJPII supports funding level parity among all the electric utilities and among the gas utilities, on a per kwh or per therm basis. Testimony/Smeloff, at 23. They support a phase-in to achieve new program funding level parity over the first four-year period. Id. NJPII asserts that program-funding levels must be determined on a statewide basis to provide geographic equity and to prevent restrictions on the development of the renewable energy market. Id. NJPII opposes inclusion of recovery requirements for past program activities in the calculations to achieve parity among all utilities in the future. Testimony/Smeloff, at 24.

AWEA supports a uniform cents/kWh charge capable of raising $128 million per year, with flexibility granted to the administrator to spend more or less than this amount in any given year as needed to maximize effectiveness of the fund. Testimony/Bailey, at 16.

DRA recommends that the rate used to recover the $106.2 million be the same, $0.00159/kWh, for all electric ratepayers after a phase-in period. Rebuttal Testimony/Nichols, at 4. DRA states that, similarly, a rate of $0.0063/therm should be phased in to collect the $22.1 million that gas company customers would have to pay under its proposal. Id.

PSE&G asserts that the allocation of additional spending should be done in a way that results in the same spending rate on existing and new programs on a cents per unit of energy basis for all electric ratepayers and for all gas ratepayers. PSE&G Initial Brief, at 6. However, if the Board decides the disparity is currently too great, PSE&G recommends the Board try to achieve parity in the shortest time possible. Id. PSE&G asserts that the utilities will likely argue this will cause rate impacts and increasing deferred balances for the electric utilities over the rate cap period and that the Board should be cognizant of these concerns. PSE&G Initial Brief, at 7. However, PSE&G argues that the Board should not fund a utility's equitable share through other utilities' ratepayers. Id. PSE&G further asserts that any deferred under-recovery resulting from this equitable spending rate can and should be recovered at a later time. Id.

PSE&G asserts that it has the highest electric DSM cost recovery because of its prior commitments and the resulting large under-recovered balance (approximately $130 million). Id. PSE&G asserts that when it has recovered that balance, its DSM rate should be lowered to a level on parity as outlined above. Id. PSE&G further asserts that this unrecovered balance must be eliminated at least by 2003 so that PSE&G's SBC rate can be put on par with the statewide average as the fourth year 14% rate discount expires. PSE&G Initial Brief, at 8.

PSE&G argues that each of the parties has its own interpretation of the Act regarding funding and allocation that supports its own interests. PSE&G Reply Brief, at 1. PSE&G asserts that unlike the other parties, it considers the funding level a matter for the Board to determine, and merely asserts that whatever the Board decides is the statewide level, that it be allocated in an equitable manner to each of the utilities and their ratepayers. Id. Allocation of funding most importantly needs uniformity. PSE&G Reply Brief, at 2.

PSE&G asserts that although the DRA argues for parity on a cents per unit energy basis for electric ratepayers and separately for gas ratepayers, it is inadequate because it is only for new programs. PSE&G Reply Brief, at 3. PSE&G asserts that it should also be for ongoing costs from existing programs, including standard offer. PSE&G Reply Brief, at 4. PSE&G argues that the DRA's conclusion that this would shift cost responsibility away from PSE&G ratepayers is incorrect. Id. Rather, it would allow other utilities' ratepayers to approach the large funding commitment already being made by PSE&G customers by increasing the percentage of new programs being funded by other utilities' ratepayers. Id. PSE&G's own ratepayers would continue to pay for the Standard Offer. PSE&G Reply Brief, at 5. PSE&G further asserts that a larger than proportionate share of new program funding allocated to a particular utility will directly benefit that utility's customers and therefore should be paid for by that utility's ratepayers. Id.

PSE&G argues that it has not proposed to reduce spending; spending would continue on existing commitments and be expanded for new programs. Id. However, PSE&G argues that it is appropriate for other utilities to fund a higher percentage of new programs to achieve a more uniform level of spending for all utilities in the state and it has not proposed to include collection of past under recoveries or lost revenues in this calculation. Id. Therefore, it does not result in shifting costs away from PSE&G ratepayers as alleged by the DRA.

NRDC supports correcting the disparity in funding levels among utilities by increasing the funding of utilities spending less. NRDC Initial Testimony, at 5.

RECO asserts that the Board should consider funding proposals on the basis of each utility's circumstances, because SBC rates have been fixed for the next four years. RECO argues that each utility is subject to different past commitments that have been approved by the Board and the ultimate goal of the Act is reduced rates. RECO Initial Brief, at 19. RECO asserts that the DRA's proposed $0.00159 /kWh would recover six times RECO's current recovery rate. RECO Reply Brief, at 2. Even with DRA's proposed phase-in, RECO argues that its ratepayers would face a four-year deferred balance of $4.2 million. Id. RECO already has a deferred balance of $3 million, which will not be fully recovered in the next four years. Id. RECO asserts that PSE&G grossly distorts the disparity among the utilities by including standard offer recovery for itself but not other utilities. Id.

The Independent Gas Utilities argue that nothing in the Act supports a uniform SBC rate. IGU Initial Brief, at 13. The IGU asserts that the DRA's proposal would double Elizabethtown's spending and quadruple it for South Jersey Gas, resulting in steep rate increases for their customers. Id. The IGU assert that the DRA submitted no evidence to show that ratepayers would benefit from increased spending. Id. The IGU further argue that PSE&G's proposal to allocate responsibility for funding based on gas sales is self-serving and would shift Standard Offer program costs to other utilities' ratepayers. IGU Reply Brief, at 3, 4.

GPU Energy asserts that PSE&G's proposal to calculate the allocation after including existing standard offer payments of $83 million, would result in an unfair allocation, placing most of the burden of funding new efficiency and renewable programs on the other utilities, regardless of the initial funding level established. IGU Reply Brief, at 7. GPU requests the Board allocate the funding on the basis of new programs alone. IGU Reply Brief, at 9.

4. Components of programs

DRA asserts that direct and indirect costs for new programs should be paid for with these funds. DRA Initial Brief, at 14. DRA states that these funds should not be used for any costs from any past programs, including costs that are due in the future from past programs. Id.

NRDC argues that the Board should exclude the cost of load control programs and transmission and distribution system lost revenues from the calculation of new program expenditures. NRDC Initial Testimony, at 5. It points out that those costs can be justified by market benefits and thus do not meet the statutory requirement of Section 12 (a)(3). NRDC Initial Testimony, at 5.

B. Administration

1. General positions

DRA recommends an independent statewide administrator for disbursement of renewable energy funds as most other states have done. DRA Initial Brief, at 27. DRA asserts that utilities are unsuitable to administer these funds because they have a history of high administrative costs and because the goals of both energy efficiency and renewable energy are not in the utilities' shareholders interest. DRA Initial Brief, at 28.

DRA recommends that the Board establish an advisory committee consisting of representatives of ratepayers, renewable energy industries, academic institutions, and government agencies to provide policy guidance to the Board and the ISA. DRA Initial Brief, at 30. DRA asserts that the

Board should appoint the Office of Sustainable Business as interim ISA. Direct Testimony/Nichols, at 9.

For the same reasons, the DRA does not support utility administration of energy efficiency programs. DRA Initial Brief, at 28. DRA recommends that the Board conduct a formal proceeding to determine how energy efficiency programs should be administered, and that the utilities continue to administer these programs only until the Board makes a decision. DRA Initial Brief, at 29. DRA states the utilities should be nothing more than collection agencies for funds to be spent on energy efficiency and renewable energy programs. Id.

The DRA asserts that utilities have failed to show why a renewable energy trust fund should not be adopted by the Board. DRA Reply Brief, at 15. DRA asserts that PSE&G is wrong that the Act is unclear on the issues of funding and administration and that these issues are in the Board's Order. DRA Reply Brief, at 16. The Act enables the Board to make this very decision. The DRA argues that the factual record supports using a statewide administrator. DRA Reply Brief, at 17. DRA asserts that the utilities have not proven that they are best able to administer renewable energy funds. Id. DRA asserts that the utilities have produced no facts that support utility administration. Utility experience in having implemented DSM programs is not sufficient to prove otherwise. DRA Reply Brief, at 18. Additionally, DRA disagrees with utilities in their claim that they have no burden of proof. Id. The requirement to file in this proceeding imposes upon them a burden to prove whatever they file. Finally, according to the DRA, no other party except NRDC supports utility administration. Id.

RECO asserts that the Act does not mention administration and that the utilities have experience in administering successful DSM programs. RECO Reply Brief, at 13. Existing accounting procedures are adequate to track funding and are consistent with the SBC mechanism. RECO Reply Brief, at 14. Utilities will cooperate through their proposed Advisory Council. RECO Reply Brief, at 14. An ISA and a trust fund would create additional bureaucracy. RECO Reply Brief, at 16. Restrictions on utility affiliates entering the efficiency and renewable energy markets are not referenced in the Act and would impede the vigorous regulatory goal of a competitive market. RECO Reply Brief, at 16.

The Independent Gas Utilities assert that an ISA is unnecessary. IGU Ex. MM2, at 30. The Independent Gas Utilities' CRA plan demonstrates that they can provide a uniform statewide program. Id. The IGU assert that the Board is capable of monitoring the effectiveness of utility administration and there was no evidence that an ISA could save money on administration. IGU Reply Brief, at 6. The IGU assert that the gas utilities' experience in DSM programs would enable the Independent Gas Utilities to administer both renewable energy and energy efficiency programs. Id. The IGU argue that the utility industry has been at the forefront of renewable energy activities such as research and development, installation of demonstration sites and pilot testing. Id. The IGU assert that there is no existing entity with experience administering a renewable energy program. Id. The IGU assert that the intervenor parties have not demonstrated that a trust fund is needed, nor does the Act contemplate it. IGU Reply Brief, at 10. The IGU further argue that the utilities already have in place Board supervised accounting systems and that the Board is well qualified to assure that there are no conflicts of interest that would inhibit the development of the renewable energy industry. IGU Reply Brief, at 12.

NJPII supports appointment of an ISA for renewable energy programs. NJPII Reply Brief, at 4. An ISA rather than utility administration will avoid obvious opportunities for conflict of interest such as promotion of utility affiliates and use of funds to promote utility identity. NJPII Reply Brief, at 7. NJPII lists several areas where conflict of interest already exists if utilities should be both administrators and implementers. Id. Separation of the functions would establish a level playing field for equal competition and assist in development of competitive and diverse renewable energy markets. Id.

NJPII points out that the renewable program should foster development and installation of distributed generation resources. Id. NJPII asserts, however, that such an effort is in direct competition with utility interests and while the Board expects to monitor inter-affiliate transactions and sanction violations, it is time consuming and expensive to watch over such actions, and violations are only sanctioned after abuses occur. Id. With an ISA, NJPII argues that utility affiliates will be able to pursue legitimate business interests without the taint of real or perceived conflicts of interest. Id.

NJPII supports establishment of an Oversight Committee comprised of stakeholder representatives to provide policy and technical guidance on renewable energy programs. Initial Testimony/Smeloff, at 27. Committee representatives should be from renewable energy industries, distribution utility companies, the Department of Environmental Protection, the Office of Sustainable Business, the DRA, and public interest and environmental organizations. Initial Testimony/ Smeloff, at 28.

NJPII lists and describes several criteria for the Independent Statewide Administrator: mission, independence, accountability, accessibility, efficiency, flexibility in program implementation, coordination and cooperation with other state agencies, and expertise in the area of renewable energy development. Initial Testimony/Smeloff, at 29.

NJPII lists the inherent limits and limited ability of utilities to meet these criteria and lists the total results of utility renewable programs as seven PV installations, two fuel cells, one solar water heater, four studies, two classroom presentations and a seminar. NJPII supports limiting costs for program administration to 5% of total program costs. Initial Testimony/Smeloff, at 32.

AWEA also asserts that costs for administration of the fund should be limited to 5% of the overall funding level. AWEA Initial Brief, at 2. AWEA opposes utility administration of SBC funds because large-scale renewable energy resources are unevenly distributed and would be difficult to develop based within service territories. AWEA Initial Brief, at 12.

individuals with knowledge and experience of the full range of renewable energy technologies. AWEA Reply Brief, at 4.

EDF asserts that an auction program is needed, administered by an ISA and open on an equal, competitive basis to all potential applications nationwide. EDF Initial Brief, at 7. EDF asserts that the utilities should be allowed to bid, but should be treated like all other bidders. Id. EDF asserts that allowing the utilities to administer the renewable funds would frustrate the policy declaration in EDECA. Id. However, EDF suggests that it is a more practical method to establish the utilities as temporary administrators of the renewable program for the first year, until an ISA can be established. Initial Testimony/Patasaw, at 7. EDF prefers an entity other than the BPU. It asserts that if the administrator is located in the BPU, but is given independence, that would be acceptable. EDF Initial Brief, at 8.

EDF disagrees with the utilities' arguments that utilities should retain the SBC revenues until spent. Id. EDF asserts that this is not just an issue of lost interest income to the ISA, but one of putting the utilities in a position to control the fund size and manner in which revenues are spent. Id. EDF states that, "Every decision would be subject to further discussion and negotiation with the BPU." Id.

The ESCO Intervenors take the position that an ISA is needed for both energy efficiency programs and renewable energy programs. NAESCO Initial Brief, at 47. The ESCO Intervenors assert that an Advisory Committee should be established to design the programs. NAESCO Initial Brief, at 49. Trust funds should also be established. Id.

Conectiv argues that the individual utilities should administer both the renewable and energy efficiency funds for their own service territories. Conectiv Initial Brief, at 19. Conectiv asserts that the parties that have proposed a specific state office be the administrator have proposed no specifics as to the statutory or regulatory authority enabling that office to oversee spending or the mechanics of how the administrator would operate. Id. Conectiv asserts that it and other utilities have made it clear that they can administer the funds efficiently and appropriately and that the record shows that Conectiv can work cooperatively with other parties and utilities. Id. Conectiv asserts that the record clearly supports Conectiv as the administrator of its own programs. Id.

Additionally, Conectiv asserts that the witness for NRDC believes the utilities can administer the programs and cites testimony, which states that the utilities know their customer base and have a reputation in the market, and that it would be a trade-off between administrative costs and utilities' familiarity with the issues. Conectiv Initial Brief, at 21.

GPU asserts that the Act does not address the issue of administration, however the extensive experience, existing infrastructure and ongoing accountability to the Board strongly support the utilities as administrators and obviates the need for a trust fund. GPU Initial Brief, at 19. GPU asserts that none of the various parties' proposals addressed adequately the issue of costs associated with initiating a statewide administrator. Id.

GPU asserts that NRDC testified that time and efficiency would be lost in shifting to a statewide administrator. GPU Initial Brief, at 20. GPU asserts that the Board should allow the continuation of the existing infrastructure for the administration of the energy efficiency and renewable programs to maximize funding and minimize administrative costs. Id. GPU further asserts that the utilities

already have established procedures to report to the Board and are subject to stringent regulatory oversight. GPU Initial Brief, at 21.

Additionally, GPU asserts that the utilities filed their plans based on the assumption that they would administer and implement the programs. Id. GPU asserts that the electric utilities provided a description of the areas of statewide coordination and areas where further coordination will be explored. GPU Initial Brief, at 22. GPU asserts that the utilities should not be denied responsibility for administration unless and until the Board determines they have not performed adequately in this regard, and this has not been supported by this record. Id.

GPU asserts that the future adoption of competition standards by the Board makes parties' concerns about conflicts of interest a moot point. Id. GPU asserts the DRA and NJPII have been the strongest proponents of a statewide administrator, but their concern is unwarranted given the Act's requirement for such standards. Id.

GPU asserts that its status as a Basic Generation Service (BGS) provider, in combination with the Renewable Portfolio Standards (RPS), are sufficient to support development of a robust market for renewable energy supply. GPU Initial Brief, at 23. GPU asserts that Mr. Smeloff for NJPII and Dr. Nichols for the DRA agreed that adequate renewable energy supply will benefit all electric suppliers given the New Jersey requirements for RPS. Id.

GPU opposes the creation of a statewide trust fund because of the potential for cross-subsidization of a utility's customers by another utility, which it asserts is inappropriate and harmful to customers of utilities who have historically aggressive Demand Side Management programs. GPU Initial Brief, at 24. GPU asserts that Dr. Nichols' opinion that energy efficiency funds should be distributed in the first four years on a dollar for dollar basis to the same service territory also applies to renewable funds and should continue as long as funds come from ratepayers. GPU Initial Brief, at 25. Additionally, GPU asserts that if the funds are going to be distributed in this manner, there is no need for a trust fund. GPU Initial Brief, at 24.

GPU asserts that no evidence was presented by any other parties supporting a trust fund as

would have no experience. Id. GPU asserts that the DRA could not recommend an appropriate administrator and recommended another proceeding to accomplish this, even though the DRA asserted there was ample supporting evidence in the record. Id.

GPU asserts that the record contains no evidence regarding participation by market players being deterred by utility administration other than GPU Energy's testimony refuting any such claims. GPU Reply Brief, at 14.

GPU argues that the DRA's assertion that the [redacted]

lower administrative costs would result from an independent statewide administrator, nor did any entity ask for the job of administrator. Id.

PSE&G asserts that although the DRA claims that utility coordination would be a good, but costly idea for the seven utilities, and that a statewide administrator would not have these multiple costs, the utilities have shown how this coordination can be achieved and costs kept low. PSE&G Reply Brief, at 7.

According to PSE&G, the DRA asserts that renewable funds should be distributed through a renewable trust fund because it will take time to ramp up for renewable projects, the monies will not all be spent in the beginning, and it is possible that spending will need to extend beyond the eight years. PSE&G Reply Brief, at 9. PSE&G asserts that this would add another administrative burden to the Board's responsibilities to establish and monitor a new entity and that the utilities' already established deferred accounting practices address both of the DRA's concerns. PSE&G Reply Brief, at 10.

NRDC proposes minimum requirements that program administrators must meet: (1) adhere to the affiliate guidelines adopted by the Board; (2) establish the program by January 1, 2001; (3) meet no less than 80% of target values for performance criteria; (4) file timely program plan updates and evaluation reports; (5) incorporate results of program evaluation; (6) maintain statewide consistency; and (7) properly and adequately staff and implement programs. NRDC Initial Testimony Att. II, at 7.

2. Trust fund

DRA recommends against phasing in funding for renewable energy projects, instead depositing the collections in a Renewable Energy Trust Fund under the control of the State Treasurer. DRA Initial Brief, at 18. This would, DRA states, ensure that these funds are spent only on renewable energy projects. Id, at 19.

NJPII supports establishment of a Renewable Energy Fund, which would collect 25% of the SBC dollars. Testimony/Smeloff, at 27. NJPII opposes deferred accounting to track spending on these programs on the grounds that there is no assurance that those funds will be spent on renewable energy and because the statutory entitlement to a specified amount of incentives will be lost. Rebuttal/Smeloff, at 5. NJPII points out that one utility has specifically proposed to use unspent funds for other purposes. Rebuttal/Smeloff, at 6. NJPII asserts that any diversion of SBC dollars from the allowed applications as set out in Section 12(a)(3) of the Act directly contravenes the statute and should not be sanctioned by the Board. Rebuttal/Smeloff, at 6.

Mr. Smeloff asserts that the establishment of a Renewable Energy Fund for 25% of collected SBC dollars for new programs on an annual basis would act as a guarantee that the mandated level of dollars would be collected, reserved, and ultimately spent on renewable energy programs and projects. Testimony/Smeloff, at 27. Mr. Smeloff points out that a fund would accommodate greater amounts of dollars flowing to projects in later years when the renewable energy industry has expanded and can utilize greater amounts of funding. Rebuttal/Smeloff, at 6. Mr. Smeloff asserts that a fund would ensure renewable energy developers of the availability of the full amount of dollars when the market expands. Rebuttal/Smeloff, at 7. Mr. Smeloff further asserts that a growing fund would be better able to support the emergence of worthwhile projects because

project financing is likely to be very time sensitive. Id. Mr. Smeloff asserts that unspent funds may be held in an interest bearing account, further enhancing the fund. Id.

PSE&G asserts that all of the issues before the Board are policy issues not factual ones and there is no requirement for the Board to make a strict finding of facts. PSE&G Initial Brief, at 2. PSE&G asserts that the utilities' responses, testimony, market assessment, and plans all have to be considered by the Board jointly. Id.

PSE&G asserts that Section 2 of the Act establishes underlying policy principles of the legislation with the key principle being decreasing the cost of energy and continue energy efficiency and load management as part of the strategy to meet long-term energy needs. PSE&G Initial Brief, at 3. PSE&G asserts that no witness challenged this as the primary objective, and that NJPII did not examine the rate impacts of their recommendations. PSE&G Initial Brief, at 4. According to PSE&G, the Board must first establish the statewide funding level and then the allocation among the utilities. Id.

GPU argues that the DRA's assertion that costs to customers are increased by the application of SBC over recoveries to Freehold buyout costs is groundless and in fact only benefits customers. GPU Reply Brief, at 9.

C. Program Design

1. Renewable programs

The DRA proposes that 60% of renewable funding be allocated to emerging technologies such as photovoltaic, small wind, fuel cells using renewable energy, geothermal, etc. DRA Initial Brief, at 41. Class I renewable technologies, excluding landfill gas to energy projects, the DRA argues should receive 30% of funding. Id. DRA asserts natural gas fuel cells should not be funded by SBC money. DRA Initial Brief, at 42. The DRA asserts that NRDC's proposals for renewable energy are inadequate because the buy down rates are too low and did not distinguish technologies by size and that EDF's proposal is better. DRA Reply Brief, at 32.

NJPII asserts that only statewide programs can ensure development of equal market opportunities and that a unified, statewide program will foster development of a renewable energy industry. Testimony/Smeloff, at 40. NJPII asserts that fragmentation of programs among utility distribution service territories will destroy markets and limit renewable supply options because it will provide artificial boundaries that do not match renewable resources, particularly for wind and biomass. Testimony/Smeloff, at 25.

NJPII further asserts that uneven funding levels and disbursed program administration will give some utility customers better access to renewable

those near market technologies that will not necessarily require direct financial incentives such as landfill methane and large fuel cells. NJPII Initial Brief, at 34. NJPII argues that limited SBC dollars should not be spent to subsidize utility RPS requirements at the expense of other emerging technologies. Id.

NJPII opposes any use of SBC monies to support technology applications that use fossil fuels. NJPII Initial Brief, at 35. NJPII specifically suggests differentiating the incentives for fuel cell projects based on the proposed feedstock fuel to be used. Id. NJPII bases this proposal on the Section 12 intention to foster development of programs providing environmental benefits above and beyond those achieved by prior programs. NJPII Initial Brief, at 36. NJPII points out that support of fossil fuel use could actually lower environmental benefits, in contravention of the legislative mandate. Id.

NJPII supports allocating 40% of the Renewable Energy Fund to foster development of grid-connected projects, 40% to market development and direct incentives for small technologies, and 20% toward development of an in-state renewable energy infrastructure. Initial Testimony/Smeloff, at 11. NJPII supports providing for an assessment of the State's wind resources on land and offshore from the 40% funding for large-scale projects. NJPII Initial Brief, at 42.

NJPII suggests that the program administrator award incentives through competitive solicitation such as a Request for Proposals or Program Opportunity Notice, based on several attributes. Id. NJPII asserts that funding could be in the form of production credits on power produced, direct project development grants, low or zero interest loans, or a combination of the above. Id.

NJPII suggests customer side incentives in the form of credits on customer bills to promote increasing sales of renewable energy products. Initial Testimony/Smeloff, at 14. NJPII suggests a buy down program for small-scale renewable projects that would be divided into tiers with incentive levels reduced over time. Initial Testimony/Smeloff, at 17. NJPII suggests allocations for small, medium and larger systems to encourage a variety of systems. Initial Testimony/Smeloff, at 18.

NJPII suggests that support for a renewable energy industry infrastructure is necessary. Initial Testimony/Smeloff, at 19. This support would include research, development and demonstration. NJPII Initial Brief, at 48. NJPII suggests it include program incentives for economic development, product development, professional training, certification and public education programs. NJPII Initial Brief, at 49.

AWEA proposes support for large-scale wind energy development through a competitive solicitation or auction process. AWEA suggests 40% or $13 million annually of the fund be used for large-scale renewable projects. AWEA Brief, at 11. This would provide production incentives and consumer incentives for wind, biomass, and non-fossil fueled fuel cells. AWEA Brief, at 10. AWEA proposes that support for large-scale wind be provided in a manner that allows developers to also take advantage of the federal production tax credits that will sunset December 31, 2001. AWEA Brief, at 13. AWEA lists the multiple financial benefits of wind development, including direct and indirect employment, increased property taxes, increased sales taxes, and lease payments and/or royalties to landowners that host wind farm development. AWEA Brief, at 6.

AWEA proposes support for small-scale wind generators by a standard incentive designed to buydown the initial equipment and installation costs of small systems. AWEA Brief, at 4. It

suggests 40% of the fund be for small-scale renewable projects, small wind and solar systems 100 kW or less. AWEA Brief, at 11. AWEA recommends the fund provide a buydown with declining incentives, as in California. AWEA Brief, at 10. It further recommends an incentive level of $4/watt, up to a limit of 70% of capital costs until 10 MW of cumulative generation is acquired. Id. AWEA suggests the next step at $3/watt would continue until an additional 20 MW of capacity is installed. Id. AWEA would also offer consumer incentives. Id.

AWEA proposes that the SBC support R&D to carry out an assessment of wind energy potential including a wind-mapping. AWEA Brief, at 11. AWEA suggests the results be provided in a publicly accessible database and an assessment of potential for off-shore wind energy development. Id. AWEA proposes that 20% of the fund be used for research, development and demonstration, education, training, certification programs and administrative costs. AWEA Brief, at 10.

EDF asserts that funds for renewable projects should be allocated to obtain the most technologies operating at the end of the eight-year period. EDF asserts that both large-scale and small-scale renewable technologies need incentives to become competitive. EDF Initial Brief, at 9.

EDF's testimony emphasizes the auction for large-scale technologies. However, they are also proponents of the auction for small-scale technology. EDF Initial Brief, at 1. EDF asserts that the Act favors competition and that a technology neutral auction is the best way to promote competition. EDF Initial Brief, at 2. Additionally, because the Act has an eight-year duration, it is reasonable to promote technologies that could achieve market competitiveness within the eight years. Id.

According to EDF, the important attributes of a technology neutral auction are compatibility with retail competitive markets, efficient use of limited funds, and administrative efficiency. EDF Initial Brief, at 3. An auction also promotes a transition to a self-sustaining renewable industry and effectively develops renewable energy within strict cost limits. Id.

EDF proposes periodic auctions over several years beginning after the first year with funds distributed on a per-kilowatt-hour production credit based on actual generation from new renewable projects. Id. EDF proposes periodic auctions to address the fact that some renewable technologies are more mature than others and to allow participation of other technologies as they become more mature during the eight-year period. EDF Initial Brief, at 4. EDF cites this as the reason to postpone the initial auction. EDF Initial Brief, at 5.

EDF also asserts that currently, market competitive technologies should not be supported by the SBC, but should be used by the utilities to comply with the RPS. EDF Initial Brief, at 4. SBC funded industries should not be used to fulfill the RPS, while there are near market-price renewable options in the regional marketplace. Id. Additionally, EDF asserts that fuel cells powered by natural gas should not be funded by the SBC even though they are included in the Act as a Class I renewable because natural gas is not a renewable resource, and will not help to achieve independence from fossil fuels. Id. EDF recommends only 10% of the SBC funds go to fossil fueled fuel cells. EDF Initial Brief, at 6.

EDF suggests that, if properly designed, there are other types of auctions that could promote competition, specifically the Program Opportunity Notice (PON) mechanism, which is used in New

York. EDF Initial Brief, at 5. In this process the program administrator allocates a portion of the SBC funds to the category of renewables and restricts the auction to that category or technology. Id. EDF recommends funds still be distributed as a production credit on a per kWh basis for generation if a PON is used. Id.

EDF proposes to allocate SBC funds as follows: 40% of the funds to technology-neutral periodic auctions, 30% of the funds to a PON auction including a 10% set-aside for natural gas powered fuel cells, and the remaining 30% to an auction of either type, but restricted to small-scale projects eligible for the buy down. EDF Initial Brief, at 6.

NRDC recommends direct financial incentives, for first cost buy down, of customer-side projects, which would decline over time. NRDC Green Testimony, at 8. NRDC supports, for grid supply resources, which it defines as primarily biomass and large wind, direct financial incentive in the form of production credits and suggests that the best way to deliver such an incentive is through an auction program. NRDC Green Testimony, at 8. NRDC supports funding demonstration projects through loans and grants and market development programs such as financing and technical assistance. NRDC Green Testimony, at 9. NRDC supports allowing flexibility in spending in any one year, so that over the period 2000-2007 the total funding will reach 25% of the total allocated. NRDC Initial Brief, at 18. NRDC supports implementation of renewable energy programs on a statewide basis. Id.

Conectiv asserts that it has proposed renewable programs, which provide environmental benefits above those provided by the standard offer or similar programs as required by the Act. Conectiv Initial Brief, at 13. Conectiv asserts that its program design was developed in a cooperative

40% of electricity sales are to the residential market and small commercial enterprises in older urban areas. DRA Brief, at 44. DRA also states: "A minimum of this 40% should be allocated to low-income energy efficiency services, which should not be less than 0.2% of total retail electric revenues." DRA Brief, at 45. DRA suggests that technology based market transformation, including efficient equipment and construction practices for all markets should be allocated 40% of funds. Id. DRA supports 10% for energy services facilitation, which would benefit large industrial, commercial, government and institutional customers. Id. DRA also supports another 10% of funding for research, development, monitoring and evaluation. Id. According to the DRA, gas funding should be allocated using the same guidelines. Id.

DRA asserts an extensive on-site audit program with direct installation for residences and small businesses should be included. DRA Brief, at 46. Audit contractors' payments should be performance based. Id. DRA asserts there should be a low-income program modeled after PSE&G's E-Team Partners, which is a direct installation program that includes energy related behavior counseling and energy bill arrearage forgiveness. DRA Brief, at 48. DRA argues that nearly all of the 40% allocation proposed for underserved markets should be spent on these programs. Id.

For market transformation programs, DRA endorses the approach used by PSE&G for heating, cooling and water heating. DRA Brief, at 49. DRA recommends a motor efficiency program developed by the Energy Center of Wisconsin. DRA Brief, at 50. For advanced efficiency practices in new building construction, DRA expresses admiration for the programs used in California by Pacific Gas & Electric Company and San Diego Gas & Electric Company. Id. DRA believes 40% of the market transformation budget should be spent on these four areas. Id. DRA believes a program should be created to facilitate performance contracting between users and energy service companies. DRA Brief, at 51. DRA asserts that air conditioning cycling should be continued, but should be moved to the competitive market. DRA Brief, at 52.

DRA states that NRDC submitted its program proposals after the hearing and so have not been subjected to the due process examination. DRA Reply Brief, at 34. DRA believes some of NRDC's proposals are useful, but not as useful as the proposals by DRA. Id.

Conectiv asserts that it has proposed energy efficiency programs, which provide environmental benefits above those provided by the standard offer or similar programs as required by the Act. Conectiv Initial Brief, at 13. Conectiv additionally asserts that this language in the Act has been the subject of debate, but that the meaning is simple. Id. New programs will provide these benefits because they incur

Conectiv asserts that many of its programs are market transformation programs. Conectiv Brief, at 17. It proposes to continue its low-income program. Id. The Home Energy Savings Program, which is a residential audit, it asserts also addresses low-income customers along with other residential customers. Id. For commercial customers, it proposed to continue its energy efficient new construction program. Id.

ESCO Intervenors recommend that standard offer type programs be used for 45% of the funding and that twenty-five percent of that should be directed to low income. ESCO Initial Brief, at 52. Direct payment for installation should be used for 55% with the programs being designed by the ISA. ESCO Initial Brief, at 53.

The ESCO Intervenors state that the utilities admit they did not design their programs based on the CRA. Id. The Board should follow the ESCO Intervenors recommendation to convene a collaborative process to design the programs, which should be results based programs, not the process based programs the utilities have proposed. ESCO Reply Brief, at 7. The ESCO Intervenors argue that standards for program design should be based on legislative intent, experience from other states, and the record evidence that results based programs will actually achieve energy savings and environmental benefits above current programs. Id.

The ESCO Intervenors assert that the utilities assume the legislature does not care whether the programs would actually achieve energy savings and environmental benefits, but that this is wrong. Utilities offer no evidence that their programs would achieve either. The ESCO Intervenors assert that RECO is incorrect in claiming the Legislature wanted to move away from Standard Offer programs. ESCO, Reply Brief, at 9.

The ESCO Intervenors assert that well-designed programs could have substantial environmental and economic benefits, but the utility programs are not well designed. Id. at 15. The ESCO Intervenors assert that adopting the utilities' proposals would defy the Legislature's intent and squander millions of ratepayer dollars. Id.

The ESCO Intervenors believe the Wisconsin Energy Conservation Corporation ("WECC") report supports continuation and refinement of performance-based programs, particularly Standard Offer. ESCO Reply Brief, at 16. A redesigned Standard Offer program is central to achieving all the purposes of the Act while maintaining a viable non-utility industry including the ESCO Intervenors. ESCO Reply Brief, at 17. They assert that GPU is incorrect in its statement that the WECC report does not find conflict between programs with measurable savings and programs that capture lost opportunities, transform markets and reduce energy costs for low-income consumers. Id.

Honeywell DMC asserts that none of the program arrays submitted in the CRA plans are approvable as filed because they meet neither the Legislature's criteria nor any reasonable regulatory standard for approval. Honeywell Initial Brief at 3.

Honeywell DMC asserts that the plans submitted by the utilities vary widely in their budgeting as a result of the funding uncertainty and that the assumptions used by various utilities are incompatible. Id. Honeywell DMC notes that GPU, in response to a discovery request from NAESCO, states that there "was little attempt to line up the programs with the outcome of the Assessment," because they were being prepared simultaneously. Id. Honeywell DMC argues that because of this, the program plans were not able to consider the results of the New Jersey

Statewide Assessment commissioned by the utilities and performed by Xenergy. Id. at 4.

Honeywell DMC argues that the presentation of specific program performance goals, benefits, and cost-effectiveness analysis are scant or non-existent in the plans. Id. Because of this lack of presentation in the CRA plans, Honeywell DMC asserts that there is no comparison of the programs selected to other options that may have been considered. Id.

Honeywell DMC asserts the plans do not adequately address existing small commercial and general residential customers. Honeywell Rebuttal Testimony, at 2. According to Honeywell DMC, the legislation did not eliminate subsidies where significant barriers remain. Honeywell DMC asserts these small commercial and general residential customers demand stronger programmatic attention and investment in order to reduce the market barriers affecting them. Id.

Honeywell DMC argues that the Board should remain concerned with ensuring equitable opportunities for all types of customers to share in program benefits. Honeywell Initial Brief, at 5. Honeywell DMC states that the Board Order should direct that customer equity be included as a policy consideration in the program plans, and that the proposed programs be revised to better address the market barriers present in the small commercial and general residential sectors, as well as in economically distressed communities. Id.

Honeywell DMC argues that the Board, prior to finalizing the plans, should first resolve the major funding and policy guideline issues in order for the program plans and budgets to be properly finalized and documented. Id. at 7.

Honeywell DMC argues that the Board Order should resolve threshold funding and policy issues, and establish a follow-up process for the revision and completion of program plans and budgets. Id. Honeywell DMC argues that the Board should establish a second-stage or compliance process concerning the specific program plans, to be conducted over a three to six month period. Id. at 8. Honeywell DMC further argues, the Board will not be in violation of the Statutory Deadlines in establishing a follow-up process for program plans and budgets following issuance of the Board's initial Order. Id.

NRDC emphasizes the importance of energy efficiency programs in reducing air pollutants that arise from the present types of electricity generation: nitrogen oxides; sulfur dioxide; carbon dioxide; and particulate emissions that result in the premature deaths of thousands of people. NRDC Initial Brief, at 14. NRDC asserts that efficiency programs must meet the statutory requirements of the Act to overcome market barriers, transform markets and make energy services more affordable. NRDC Green Testimony, at 7. To accomplish those goals, NRDC asserts that the programs must be consistent statewide. NRDC Initial Brief, at 16. It offers proposed budgets and minimum requirements. NRDC Initial Brief, at 16, Att.1.

NRDC proposes seven residential efficiency programs. For each program, all electric utilities would meet regularly to coordinate the development of a consistent program design and to ensure the program is implemented in a consistent fashion across the state. The programs recommended by NRDC are:

- Residential Appliance Program. This program would be available to all residential customers to encourage, through marketing, the purchase of Energy Star home

equipment, (refrigerators, clothes washers, dishwashers, room air conditioners, DVD, home audio, televisions/VCR combinations, and VCR's and six office equipment products. The program would provide financial incentives ($100) toward purchase of Energy Star clothes washers and ($300) toward purchase of suites of Energy Star appliances.

- Residential Efficient Lighting Program. It would promote Energy Star lighting products to residential and non-residential customers through marketing and brand awareness, sales training and point of sale customer incentives for screw-in lamps, hardwired fixtures, recessed cans and torchieres.

- Residential Electric HVAC Program. For any residential customer or builder purchasing a new central air conditioner or heat pump, the program goal would be to achieve a statewide market share of 10%. Other incentives would be for Energy Star thermostats and duct sealing.

- Residential Retrofit Program. It would apply to all individually metered customers with a primary target of 1-4 unit dwellings. It would provide consumer education and remote audit services at low or no charge. Estimated costs are $5 per unit for remote education services and from $8-$12 per unit for remote audit services.

- Residential Gas HVAC Program. It would apply to any residential customer or builder purchasing a new gas furnace or boiler. It would provide incentives for purchase of Energy Star rated equipment. The incentives would be $350 in the first year, gradually declining to $100-$150 after four years.

- Residential Low Income Program. It would be available to any household with income at or below 150% of the federal poverty guidelines and to seniors receiving Lifeline assistance. It would provide all cost-effective efficiency measures in each home with no cost cap. Program goals will be to generate 15% to 20% energy savings per participant for approximately 7,500 low income households per year.

- Residential New Construction Program. Any new home with gas heat, electric heat and/or central air conditioning would be eligible. The program would provide incentives of approximately 100% of the incremental cost of efficiency upgrades for homes with electric or gas heat, and 50% of the incremental cost for homes with central air conditioning and oil or propane heat. Program goals would be to achieve a 13% statewide market share for Energy Star homes in 2000, rising to a 34% market share in 2003. NRDC Initial Brief, Att.1.

NRDC proposes three commercial/industrial ("C&I") efficiency programs. For each program, all utilities would meet regularly to coordinate the development of a consistent program design and to ensure the program is implemented in a consistent fashion across the state. The proposed programs are:

- C&I Construction Program: It would apply to commercial, educational, governmental, institutional, industrial, and agricultural customers engaged in customer-initiated construction events. It would provide seven core programs and four specialized

markets/program paths. Program goals would be efficiency improvements in at least 5% of the new and renovated commercial floor space under construction in 2002.

. C&I Research and Development Program: It would initially consist of the following initiatives: motor services, new initiatives for unitary HVAC performance, and new technology assessment and program integration. The utilities would meet the following minimum program requirements: develop the administrative structure necessary for the technology assessment initiative within six months of BPU approval; develop and begin implementing a coordinated technology assessment initiative within nine months of BPU approval; begin the operation of the motor and HVAC installation of pilots by the end of 2000.

Operation & Maintenance ("O&M") and Recommissioning Program: It would target existing commercial and industrial buildings and facilities, including schools and institutions. It would begin a new building operator training and certification program, or enhance one or more existing programs. It would lay the groundwork for subsequent O&M initiatives and help building owners and managers to recognize the value of good building O&M practices.

RECO asserts that its proposed programs satisfy the requirements of the Act. RECO Initial Brief, at 40.

According to GPU, the DRA does not understand the load control program as shown by its recommendation that GPU reinstate the incentive payment. GPU Rebuttal Brief, at 28. GPU asserts that its program is successful as designed with the use of the radio controlled setback thermostat as the incentive. Id. GPU asserts that provision of an additional incentive would increase program costs probably above the benefits to the State. GPU Rebuttal Brief, at 29.

PSE&G asserts that its programs should be approved as filed, with a requirement that it submit a compliance filing (which will detail the budgets for each program) after the Board decides the spending level. PSE&G Initial Brief, at 12. PSE&G also recommends that the Board establish working groups, if further alignment of programs is necessary, among the utilities. Id.

PSE&G disagrees with NRDC's position that the Air Conditioning Cycling Program should not be funded through the SBC, asserting that it was approved by the Board in 1991 as a DSM Program. PSE&G Reply Brief, at 2. PSE&G further asserts that the Board's August 24, 1999 Order does not mention moving the program into base rates from the SBC and that the Board approved recovery for this program's costs through the SBC in its October 1, 1999 Order. Id. PSE&G argues that it would be unfair to take costs out of the SBC when the Company has no regulatory means to change base rates to accommodate its recovery. PSE&G Reply Brief, at 3.

PSE&G asserts that the ESCO Intervenors effort to continue the standard offer programs are based on regulations adopted in 1991 and further argues that their reliance on the Act's phrase about environmental benefits above and beyond standard offer demeans the Act's mandate that market transformation be considered in the Board's decision. PSE&G requests that the Board ignore the arguments in the ESCO Intervenors' Initial Brief. Id.

3. Additional program elements

The Independent Gas Utilities state that the record supports the Independent Gas Utilities' plan as meeting all of the requirements of the Act. IGU Initial Brief, at 2-3.

GPU asserts that no non-utility party submitted any detailed program designs although several proposed general concepts without sufficient detail to allow a response. GPU Rebuttal Brief, at 27.

GPU asserts that the Board cannot give any weight to the program designs submitted by NRDC as they were submitted after the close of hearings and therefore allowed no party the opportunity to submit discovery or cross-examine the preparer. Id. GPU Energy asserts that because these program designs are unsupported by the record, the Board must reject them. GPU Rebuttal Brief, at 28.

The ESCO Intervenors assert that NRDC's proposed performance goals and indicators must be rejected because they do not present any evidence during hearings and any such goals and indicators should be developed by a collaborative working group, not a single party. ESCO Reply Brief, at 14,15.

NRDC proposes Renewable Energy Programs – in which the SBC will support: 1) Small-scale technologies sited on the customer side of the meter side of the meter; 2) Projects for grid supply; and 3) Research, development and, commercialization projects and market development. NRDC Green Testimony, at 8.

a. Performance incentives and lost revenue recovery

PSE&G asserts that it should recover lost revenues and earn administrative performance incentives for both energy efficiency and renewable programs. PSE&G Initial Brief, at 11. PSE&G asserts that no matter who administers the programs, the rationale for lost revenue recovery, or the recovery of fixed costs lost due to saving a unit of energy that would have been recovered had the unit of energy been sold, continues. Id.

PSE&G has proposed performance incentives for most of its programs, which are to be paid to the administrator on the basis of implementation and results. Id.

DRA opposes any performance incentives for administration of energy efficiency programs. DRA Initial Brief, at 31, 33. If the Board were to allow incentives, DRA believes there should also be disincentives. DRA Initial Brief, at 34. DRA opposes recovery of lost revenues because utilities have opportunities in the competitive market to offset these losses. DRA Initial Brief, at 35. DRA recommends that the Board establish an advisory committee consisting of representatives of ratepayers, renewable energy industries, academic institutions, and government agencies to provide policy guidance to the Board and the ISA. DRA Initial Brief, at 25, 26. The Board should appoint the Office of Sustainable Business as interim ISA.

DRA argues that PSE&G's request for lost revenue recovery should be rejected because the foundation upon which it relies has been unraveled by the unbundling and restructuring of the electric industry. DRA Initial Brief, at 35. No utility has supplied any data to justify the inclusion of

performance incentives for itself in its program. DRA Initial Brief, at 31. Additionally, PSE&G has merely set easily reachable targets for itself. Id.

AWEA opposes use of the fund as a means of recovering revenues lost as a result of small-scale renewable energy facilities that reduce utility sales. AWEA Initial Brief, at 2.

NRDC opposes permitting the utilities to collect lost revenues associated with new program investments because the rationale for such recovery no longer exists. NRDC asserts that the rationale was to secure the utilities' indifference between demand-side and supply-side investments when determining how best to serve customers' needs in the context of integrated resource planning. According to NRDC, the electric industry no longer operates under the paradigm of integrated resource planning. Instead, NRDC asserts, the purpose of investing in energy efficiency and renewable energy programs is to maximize the public benefits they deliver. NRDC Initial Brief, at 9. NRDC argues that permitting utilities to recover lost revenues could allow the utilities to take in 24% or up to $30 million of the $128 million intended for actual program investments. NRDC Initial Brief, at 11.

GPU asserts that although the proposal to earn performance incentives has been opposed, certain parties support them as a way to assure performance. GPU Rebuttal Brief, at 17. According to GPU, several parties also opposed collection of lost transmission and distribution revenues, however it asserts that no one has provided a convincing argument as to why the utilities should not be made whole. GPU Rebuttal Brief, at 19. GPU asserts that the NRDC's and DRA's arguments on the subject make evident its lack of understanding of the purpose of lost revenue recovery. Id. GPU asserts that performance incentives for utility administrators will not make them whole for the revenues lost. Id. GPU further asserts that rates were merely unbundled during electric restructuring, which means the DSM related lost transmission and distribution ("T&D") revenues were not accounted for. GPU Rebuttal Brief, at 20. GPU asserts that disallowing recovery prospectively would equate to reducing the utilities' return on equity outside of a base rate case. Id. GPU therefore asserts that they should be allowed to collect lost T&D revenues associated with past and current programs until its next base rate case. Id.

PSE&G asserts that other states which have continued funding for energy efficiency and renewable energy have made their goal transition from resource acquisition to market transformation. PSE&G Rebuttal Brief, at 8. PSE&G asserts that measuring the performance of market transformation programs is basically a function of achieving certain implementation milestones and tracking changes compared to a market baseline. Id.

PSE&G disagrees with the DRA that its performance standards are too easily achievable and within PSE&G's direct control. PSE&G Rebuttal Brief, at 9. PSE&G asserts that the Board would have to approve the standards and that it is very unlikely the Board would approve standards which are not sufficiently stringent. Id. Further PSE&G argues that the standards must be agreed to upfront and must be approved by the Board. Id.

Regarding the DRA's argument that incentives must be accompanied by equivalent under-performance penalties, PSE&G asserts that the loss of performance incentives alone is sufficient penalty for under-performance and that the Board can always take further action against any administrator not performing adequately. Id.

PSE&G disagrees with the DRA's assertion that because the Act makes no reference to lost revenue recovery, PSE&G should not be allowed to recover lost revenues. PSE&G Rebuttal Brief, at 10. PSE&G asserts that the lack of reference in the Act actually supports the appropriateness of lost revenue collection. Id. PSE&G also disagrees with the DRA assertion that PSE&G amended its filing to seek lost revenue recovery for renewable energy programs. Id. PSE&G asserts that it was merely clarifying the record and that it was always its intention to seek recovery of lost revenues for renewable energy programs. PSE&G Rebuttal Brief, at 11. PSE&G asserts that the DRA's argument that DSM programs do not have to impact rates is flawed. Id. Without lost revenue recovery, PSE&G would require more frequent base rate cases to address the fixed cost revenue erosion resulting from the successful energy efficiency and renewable programs which reduce sales. Id.

Additionally, PSE&G asserts that the DRA's concern that PSE&G fails to consider the long-term benefit of reduced transmission and discharge is unfounded. Id. PSE&G asserts that it considered these benefits, but while there are long-term benefits, recovery of lost revenues addresses the short term fixed cost losses linked to existing plant. Id.

NJPII opposes recovery of lost revenues for renewable programs, pointing out that the legislation makes no provision for such recovery, and that the rationale of lost revenue recovery is no longer applicable in light of the new mandates for program funding. NJPII Initial Brief, at 38. NJPII emphasizes that energy supply requirements are no longer the sole responsibility of distribution utility companies and that utilities can no longer maintain an expectation of cost recovery for generation losses. Id.

b. Free ridership

Free ridership is a concept which asserts that certain customers would install the more efficient product even without a program or incentive. However, they take advantage of the program anyway. These customers are considered free riders.

The DRA asserts that if the Board adopts lost revenue recovery, a robust free rider discount should be applied. DRA Initial Brief, at 37.

GPU asserts that the DRA's supplemental testimony on free ridership was submitted in the middle of hearings so that no party had the ability to rebut the testimony. GPU Rebuttal Brief, at 20. GPU further asserts that because of this late submittal, the information in the record is inadequate for the Board to decide anything different than the currently approved 10% for rebate programs and zero for long-term ESCO contracts. GPU Rebuttal Brief, at 22.

According to PSE&G, the DRA claims that PSE&G has ignored the free rider effect on lost revenue calculation. PSE&G Rebuttal Brief, at 11. PSE&G asserts that free riders, if they exist for any program, need to be accounted for in the calculation of energy savings and that these adjusted savings should be used in all applications, not just lost revenues. Id.

c. Standard offer

GPU asserts that there is a mismatch between the Act and a standard offer or standard performance contracting program, and that the DRA recognized it in its brief. GPU Rebuttal Brief,

at 22. GPU asserts that the Board should not require any such new commitments similar to the "staggering long-term debt associated with standard offer programs." Id. Additionally, GPU claims that SESCO's and NAESCO's assertions that the utilities are unconcerned with the cost effectiveness of their programs are untrue. Id. GPU further asserts that the proposal made by SESCO for a standard offer type program would guarantee spending without ensuring it is linked to savings, and that such a program cannot be cost effective or transform markets. GPU Rebuttal Brief, at 23.

d. Market assessment

GPU opposes the SESCO and NAESCO argument that the utilities failed to abide by the CRA results in designing their programs. GPU Rebuttal Brief, at 24. GPU asserts that SESCO and NAESCO erroneously defined CRA as the Market Assessment, but that the CRA is the responsibility of the Board pursuant to the Act, while the Market Assessment was merely one element of the CRA. Id. GPU asserts that the Market Assessment evaluated the technological and market potential of particular technologies and program concepts. GPU Rebuttal Brief, at 25. GPU asserts that its Plan 2000 fulfills the Act's requirement to propose renewable and efficiency programs and that those programs addressed most measures in the Market Assessment to the extent that those measures were consistent with the Act. Id.

D. Other

1. Environmental benefits

GPU asserts that SESCO and NAESCO obfuscate the real issues with their claim that the utilities did not consider the requirement in the Act for programs to provide environmental benefits above and beyond existing standard offer or similar programs. GPU Rebuttal Brief, at 26. GPU asserts that this argument denies the reality that even if the utilities implemented the same programs, new environmental benefits would be realized, which the Act does not require be quantified or reach a particular level. Id. GPU asserts that the Board should nonetheless be concerned about the environmental benefits of the new efficiency and renewable programs and estimates its Plan 2000 will generate 38MW of load reduction over four years. GPU Rebuttal Brief, at 27.

The ESCO Intervenors assert that the utilities did not address the overall goal of the Act of providing environmental benefits above and beyond standard offers. The ESCO Intervenors assert that the utilities have not quantified the environmental benefits of current programs or of their proposed programs to demonstrate that they have met the Act's overall goal. The Board can only comply with the Act by rejecting the utilities' filings. ESCO Initial Brief, passim.

2. Miscellaneous

Based on the model of the renewable energy portfolio standard, DRA recommends that the Board adopt an energy efficiency portfolio standard in the second four-year period of CRA. Energy efficiency should be included in the Universal Service Fund. DRA Initial Brief, at 54.

The ESCO Intervenors assert that the utilities have failed to provide any essential information, therefore the Board should reject their proposals. The ESCO Intervenors assert that the utilities have not proved they will achieve market transformation, which is not a goal of the Act anyway, because there are criteria for market transformation. The utilities have not based their programs

on a Comprehensive Resource Analysis as required by the Act. In contrast to the utilities, the ESCO Intervenors state they have given the Board the guiding principals for the Board's decision. The Standard Offer program should be enhanced and improved, not discarded, or the Act's requirements will not be met. The ESCO Intervenors assert the Legislature wants measurable results, not process. The ESCO Intervenors state that market transformation and lost opportunities are captured by standard offer programs. The ESCO Intervenors recommend the Board issue a remedial order or require the parties to collaboratively develop the components of a remedial order, as follows: the Board should determine the appropriate funding for energy efficiency and renewable energy sources, then direct the parties to develop, in 45-60 days, the essential components for the remedial order. According to the ESCO Intervenors, the Act does not require that detailed program plans must be established and implemented by February 9, 2000. It only requires that funding be determined. Even though the Act states that the "...Board shall simultaneously determine ... the programs to be funded..." the ESCO Intervenors assert that the Board should not interpret that to mean that detailed program plans must be established or that programs begin by any specific date. The ESCO Intervenors believe the Legislature intended the Board to engage in a multi-step process. The Board must first determine the environmental benefits of the Standard Offer and similar programs. This should then be the baseline used to evaluate programs and the appropriate funding. The Board should then determine which programs, efficiency and renewable, will result in "measurable" environmental benefits above the baseline. ESCO Intervenors state that the utilities falsely claim market transformation is the principal legislative goal. ESCO Initial Brief, passim.

Eastern Heating and Cooling Council (EHCC), which did not submit either an initial brief or a reply brief, is a non-profit educational organization that has been providing training to HVAC contractors in New Jersey since 1990. They also provide information to consumers and businesses about energy efficient equipment and available incentive programs. EHCC has been working, as part of the New Jersey Residential HVAC Working Group, to develop a common platform for residential high efficiency HVAC programs implemented by the utilities. This platform includes more stringent installation requirements for rebate qualification for heat pumps and air conditioning systems and use of sizing calculations.

Currently, only GPU and PSE&G require all of these to qualify for a high efficiency HVAC rebate. Conectiv requires sizing but not airflow and system charging documentation. EHCC recommends that Conectiv adopt these requirements in order to provide the entire state with a uniform program platform.

IV. SETTLEMENT PROPOSALS

As noted above, in its orders establishing the procedures for this matter, the Board encouraged the parties to attempt to negotiate a settlement of the issues. The Board established deadlines for the submission of any negotiated settlement and the opportunity for the parties to comment thereon. While, unfortunately, the parties were unable to agree to a single stipulation, two groups did reach a general consensus. One stipulation (Utilities/NDRC Stipulation) was signed by the NRDC, EDF, EHCC, AWEA, BP Solarex, RV and six of the seven New Jersey electric and gas utilities, RECO being the lone exception. The second stipulation (DRA Stipulation), was joined by DRA, NJPII, NAESCO, ONSITE SYCOM, Astropower, Inc., EPV, GeoSolar, Inc., Green Mountain.com, H Power Corporation, Mid-Atlantic Solar Energy Industries Association, Siemens Solar Industries and BP Solarex. The key substantive elements of each stipulation are summarized herein below.

A. Utilities/NRDC Stipulation

The statewide level for energy efficiency and class I renewable energy from 2000 - 2003 is $423 million. Funding over the four years would be as follows: for 2000, the funding is $70 million; for 2001 it is $108 million; for 2002, it is $120 million; and in 2003 it is $125 million. The proposed allocation between energy efficiency (EE) and renewable energy (RE) respectively for each of the four years is as follows:

	2000	2001	2002	2003
EE	64.05	91.8	97.8	97.5
RE	5.95	16.2	22.2	27.5

The average is $105.75 million per year. The statutory eight-year funding period would begin in 2001, while the year 2000 would be a transition year.

For years 2000-2003, the funding allocation among the utilities is as follows:

	2000	2001	2002	2003
PSE&G electric	$26.9	$40.2	$43.1	$43.2
PSE&G gas	$12.4	$19.4	$21.9	$21.8
GPU	$20.2	$30.2	$32.7	$34.8
E'TOWN	$ 1.9	$ 3.7	$ 4.0	$ 4.2
CONECTIV	$ 4.7	$ 7.6	$ 9.8	$11.4
SJG	$ 1.2	$ 2.1	$ 2.8	$ 3.5
RECO	$ 0.4	$ 1.1	$ 1.7	$ 1.9
NJN	$ 2.3	$ 3.7	$ 4.0	$ 4.2

RECO is not a party to this stipulation and did not agree to these numbers.

New programs would include direct load control programs for 2000-2003 only, but are not subject to new incentives, and they would be capped at $3.90 million for PSE&G, $1.8 million, for GPU, and $4.2 million for Conectiv. Performance incentives are included on energy efficiency and customer sited clean energy generation programs. Legacy program costs are not included. GPU will discontinue measurement and verification on legacy programs, and use that money for new programs. Also, new program lost revenues is not treated as a new program cost. No earnings test as set forth in the DSM regulations would be used for lost revenue recovery.

No trust fund is proposed. An ISA would be established for supply side renewable energy programs, which would bill the utilities periodically for funding, but the utilities would administer the energy efficiency and customer sited renewable energy programs. Funds for new programs that are not spent can be carried forward into the next year or spread over future years. If overspending occurs, that amount can be deducted from a subsequent year's budget. However, utilities would strive to meet program goals.

Performance incentives for meeting certain goals are proposed in combination with a provision that poor performance could potentially result in the withdrawal of program administration responsibility.

Administrative Costs (as percent of budget)

	2000	2001	2002	2003
Customer sited	21%	9.4%	4.3%	3.6%
Grid-Supply	20%	8.5%	4.0%	2.8%
Market Dev.	9.2%	2.3%	1.6%	1.4%

A Renewable Advisory Panel would appraise the development of renewable energy in New Jersey and make recommendations on how to allocate funding effectively.

Three statewide renewable energy programs are proposed and would be consistent statewide. The first program would provide direct buydown incentives for customer sited small wind, sustainable biomass, photovoltaics, and fuel cells. The program is intended to develop market demand for these technologies and to develop an infrastructure to support installation and maintenance of these systems. The grid-supply program would provide financial incentives to encourage renewable grid connected electricity generation, which so far has not been successful in New Jersey. The third program would have the ISA fund research and demonstration projects in order to enhance the first two programs.

Gas utilities will allocate 100% of their renewable funds to the customer-sited program and with that would fund only gas-fired fuel cells. Electric utilities would fund the other renewable technologies such as photovoltaics and small wind technologies. The budget, on average, for renewables for four years is 17% of the total budget, but asserted to be 25% over nine years. No more than 60% of the funding over 2000-2003 can go to any one of three renewable programs. There is a four-year ramp-up of funding: $6 million, $16 million, $22 million and $27 million for a total of $72 million.

The renewable funding can go to 25% during the first four years if there is a demand for additional funding. Recovery will be allowed for budget amounts exceeded for customer-sited program expenses. Additional funds may come from future budgets and unused energy efficiency budgeted funds.

For customer-sited programs to address concerns that a consistent program be available in all service territories, if funds are exhausted, funding would first come from future renewable budgets, through 2003. If those funds are exhausted, funding would come from its energy efficiency budgets not already committed. If additional funds are still needed, a utility can ask the Board to order the ISA to provide additional funding from surplus funds. If the funding is still inadequate, the utility may petition the Board for funds from other utilities available customer-sited funds. Any utility can agree to shift customer-sited funds or use more than its share and request recovery from the Board.

The Utilities/NRDC Stipulation proposes the Grid-Supply Clean Energy Generation program, which will complement the Renewable Portfolio Standards to address market barriers. Specific strategies will support particular needs of each technology, production incentives (e.g., auction for $/kWh

incentives), risk mitigation (e.g. insurance, loan guarantees), and below market financing. The RPS establishes demand and the Grid-Supply Program will focus on supply-side equipment, suppliers, project developers, market support for green consumers, project financing, siting and regulatory approval.

For the year 2000, the utilities allocated 75% of their energy efficiency funding for the residential sector and 25% of their funding for the commercial and industrial sectors with the following programs. The Residential Electric Heating, Ventilation, and Air Conditioning (HVAC) program promotes improved efficiency, proper sizing and installation as well as Energy Star programmable thermostats. The Residential Gas HVAC program promotes Energy Star furnaces, boilers, high efficiency gas water heaters and Energy Star programmable thermostats. In 2000, incentives was to vary by utility; in 2001, all gas utilities will offer the same program. The Residential Windows Program promotes Energy Star windows. No incentives are proposed. The Residential Low Income Program provides direct installation of efficiency measures, energy education and arrearage forgiveness for those with income at or below 150% of the federal poverty guidelines. The Residential New Construction Program provides improved efficiency of gas heat, electric heat and/or central air-conditioned residential buildings using incentives and other mechanisms. The Residential Retrofit Program provides information about energy use and efficiency through the Internet and by mail, free of charge.

The Residential Lighting Program is designed to transform specific components of the residential lighting market, particularly fixtures. The Residential Appliance Program will promote Energy Star appliances with an initial focus on refrigerators, clothes washers, dishwashers and room air conditioners. No consumer incentives are proposed.

The Commercial & Industrial Energy Efficient Construction Program consists of seven core programs and six specialized markets/program paths. The core programs include: 1) prescriptive efficiency measure rebates; 2) custom incentives for more complex measures; 3) comprehensive incentives for more comprehensive measures; (4) design incentives and support, to architects and engineers; 5) technical assistance to help customers evaluate energy efficiency options; 6) incentives for technical support for commission services; and 7) coordinated marketing strategy. The specialized markets/program paths include: 1) chiller replacement; 2) school and state/municipal government facilities; and 3) lighting remodeling. The Program will also provide contractors with specialized marketing and training, technical support for state's commercial building code, an initiative to enhance efficiency of customer motor management practices, and an initiative to encourage efficient installation of unitary HVAC equipment. The Commercial & Industrial Building Operation & Maintenance Program is designed to provide improved building operation and maintenance practices. The Compressed Air System Optimization Program is designed to capture significant energy savings from these industrial systems, but applies only to GPU and PSE&G.

Under the Residential Air Conditioning Cycling Load Control Program, certain utilities will continue to use air conditioning cycling strategies to lower peak demand on days of system peak. Incentives vary by utility. Through the School Energy Efficiency and Renewable Program, GPU and PSE&G will make available grants, materials, etc. to learning institutions.

The transmission and distribution lost revenue associated with energy efficiency programs may be collected from 2000-2003 through the SBC, but there will be no lost revenue recovery for

renewable energy programs. Lost revenues may not be included as part of new funding. Lost revenue will be calculated using the to-be-approved evaluation plan. The fixed margin applied to the lost KWh, Kw and therm will be calculated each month by rate schedule. GPU will collect a transition payment equal to 90% of lost revenues and incentives in lieu of said recovery for legacy programs.

Performance incentives are proposed as up to 8% of the program costs budgeted and are included in new program costs. Incentives can be earned by the utility administrator for implementing energy efficiency and customer-sited renewable energy programs. Uncollected incentives can be carried to the next year for program expenditures.

B. DRA Stipulation

The funding level for the first four years is $128 million per year based on fifty percent of the $256 million being collected, for a total of $512 million. Funding is proposed as a uniform spending rate for electric ($/kWh) and for gas ($/therm), although it is acknowledged that there may have to be a phase-in for some utilities over the first four years. The spending rate should apply to both energy efficiency and renewable energy, and should not include past DSM commitments. For the electric utilities, the rate should be $.00159/kWh. For gas utilities, the rate should be $.00063/therm. Renewable energy funds should only be collected from electric ratepayers. The allocation for funding for energy efficiency programs would be $22 million from gas rates and from electric rates $74 million plus $32 million for renewable energy programs from electric rates.

This stipulation includes no load control programs as part of the new programs because it is considered more appropriate that they be on the unregulated side after the first year. Monies collected for renewable energy programs would be put in a trust fund, and a separate trust fund would be set up for energy efficiency monies collected. There would be an ISA for both energy efficiency and renewable energy programs with regulatory oversight, which would prevent business conflicts of interest. Additionally, an ISA is less costly and maximizes marketing funds. The administration of energy efficiency would be transitioned to an ISA and if the Board selects a non-government ISA, performance incentives would be acceptable.

A uniform set of programs would be available to all without regard to utility franchise territory. For large scale, grid supply projects there would be a Competitive Solicitation Program and a Customer Credit Program, which is a credit on customer bills for the extra cost of renewably produced kwh. For small scale, distributed generation, there would be direct incentives or "buy down" based on the system rated capacity, which would decline with increasing size and over time.

The allocation of the funding for renewable energy programs proposed is 40% for large scale, grid-supply technologies and the Customer Credit Program, 40% for the "buydown" for small scale (<100 kW) or distributed generation with a 60% project cost cap, and 20% for infrastructure programs, which are economic development, research development and demonstration, training, certification, and education.

The SBC funds should provide incentives for emerging technologies, no near-market technologies that would be supported by the RPS should be funded by the SBC. The stipulation proposes an Advisory Committee to monitor technology development to determine which types are "near-market". Methane from landfills is considered "near-market" and should therefore not be supported

by these funds.

Renewably fueled fuel cells should receive incentives, whereas fossil fueled fuel cells should not receive incentives. However, if such facilities are funded, they should receive significantly lower incentives.

The funding allocation is divided among three energy efficiency program categories as follows: 47% to pay for savings (P/S), 45% to pay for technology (P/T) and 7% to pay for infrastructure (P/I). The allocation of funding by sector is 45% residential, 50% commercial and industrial and 5% research and development.

The Advisory Committee proposed to assist the Board and ISA in program design will design specific program measurement protocols. For pay-for-savings programs measurement will be based on USDOE standards. Measurement and payments are limited to three years regardless of measure life. Contractor payment flexibility and deemed savings will be allowed for some equipment.

The DRA recommends that up to ten energy efficiency programs be available statewide. Five programs are proposed for residential customers with details to be determined by the Advisory Committee: audit based retrofit (P/S), which provides comprehensive audits; direct-install measures; the sale to non-low-income households at market rates of comprehensive measures, HVAC (P/T; P/I), which provides incentives for the sale and installation; appliances (P/T P/I), which also provides incentives for the sale and installation; and new construction incentives (P/T). Four C&I programs are proposed and one for research and development. No lost revenue recovery for new energy efficiency and renewable energy programs are permitted under any circumstances.

V. COMMENTS ON THE SETTLEMENT PROPOSALS

With receipt of the Utilities/NRDC Stipulation and the DRA Stipulation, the Board's schedule for comments was met. Filed comments were received from the following: RECO, EDF, NJPII, AWEA, DRA, DMC, SESCO, jointly from the six signatory gas and electric utilities and NRDC. NAESCO, ONSITE SYCOM, and NJESCO submitted a joint comment. NRDC supported its own stipulation. In addition, the Board also received a letter generally supporting the Utilities/NRDC Stipulation. Key elements of the comments provided by each entity are summarized herein below.

A. Comments on the Utilities/NRDC Stipulation

1. EDF

EDF asserts that the Utilities/NRDC Stipulation under-funds energy efficiency and renewable energy in the first four years by $89 million based on $128 million per year. Renewable energy should get $32 million per year for the first four years. However, the stipulation does not even allocate 25%. EDF believes that the Act requires 25% per year not an average of 25% over eight years. There is no assurance included for 25% in eight years.

The Utilities/NRDC Stipulation allots too much funding for small-scale renewable energy projects and not enough for grid supply projects. As the California experience shows, small scale distributed generation may not use all of the subsidies. However, grid-scale programs are taking full advantage. The auction is fully subscribed. Therefore, a larger portion should go towards grid-

scale projects. EDF approves of the auction mechanism proposed in the stipulation for grid supply. However, its funding is too modest.

EDF supports an ISA for program administration and believes that the stipulation should be further expanded to provide an ISA for small-scale renewable energy programs, at least to ensure that funds foster competition and deregulation. It is unclear from the stipulation whether the ISA holds the funds, in what type of account, and if interest stays with the ISA. It should be in a secure, interest bearing account. Energy efficiency can obtain funds from any ISA surplus, but not the reverse. EDF asserts that it should be reciprocal.

EDF's signing of the agreement is done with the understanding that these issues will be addressed and resolved.

2. NJPII

The Utilities/NRDC Stipulation does not adequately foster competition, and although it attempts to do this for renewables, it is not enough, particularly with regard to utility control over small technologies. The administrative structure proposed is overly complex to maintain control over the renewable energy program and the flow of dollars. New programs should be funded at the legislated levels, money should be maintained in trust funds, an ISA should be appointed for all renewable programs, and at least 90% of program dollars should be budgeted for technologies.

The Utilities/NRDC Stipulation is very detailed for three renewable programs, but they are not in the record, and the budgets proposed are not supported by evidence. The budgets list numerous activities without providing information on why activities are appropriate. The Utilities/NRDC Stipulation budgets for target marketing and market facilitation, which should be done by the providers of renewable products at their own expense. Bolstering utility name identity should not be a goal of Board decisions on administration or budget issues in these proceedings. Administrative costs are too high. Without the opportunity for debate on stipulation proposed activities and budgets, the Board has no record to base acceptance of these renewable programs. The funding does not meet either the 50% or the 25% level in the Act until the utility stipulation promises to make up the shortfall in the out years. Energy efficiency and renewable energy will compete for funds at a time when both will need to increase funding. Trust funds are needed to protect the public.

The DRA Stipulation recommends a 5% administration cap on all functions that the Utilities/NRDC Stipulation identifies as administration, market analysis, program development and planning, monitoring and evaluation. The Utilities/NRDC Stipulation's buy down program alone has 42% of the total budget in 2000 to these administrative functions, reducing to 9% in 2003, and 17% in 2003. The Utilities/NRDC Stipulation's buy down program must be modified to allow competitive markets to result.

Allowing natural gas fuel cells to participate, and then separating them from competition with other renewables creates a guaranteed market for natural gas fuel cells. The Utilities/NRDC Stipulation states natural gas fuel cells are Class I technology. The Act is silent on this except in general on fuel cells. Over 25% of renewable funds are set aside for natural gas fuel cells. Fuel cells should have to compete with other technologies.

Renewable programs should not be designed to create additional market opportunities for transmission and distribution utilities. Technologies should not be limited by service territories because some customers will have more access to renewable technologies than others, which may distort the renewable energy market. Competitive disadvantages will result if the utilities can market renewable supply options in their service territories, simultaneously offering energy products through affiliates.

Preferred administration is a neutral ISA to implement all the renewable energy programs at reasonable capped administration cost.

An all-source auction for large technologies is premature. If it is purely price based, technologies with lower costs have access to more of the funds, which may result in a limited number of technologies. An auction should consider other factors to help ensure diversity. The DRA Stipulation has an initial competitive solicitation program to construct initial projects in New Jersey. After successful implementation and market conditioning, a competitive auction would take place, creating a foothold for a variety of large-scaled technologies.

Collaborative processes for drafting regulations and program design, exclusive of public input, are unlawful.

NJPII recommends the Board adopt the DRA Stipulation recommendations for funding level, administration and program design for energy efficiency and renewable energy.

3. AWEA

Its support of the NRDC proposal does not mean AWEA is opposed to independent administration of clean energy funds. AWEA supports independent administration.

4. NAESCO, ONSITE SYCOM, NJESCO

The Utilities/NRDC Stipulation fails to meet the Act's requirements. The primary difference between the Utilities/NRDC Stipulation and the DRA Stipulation is that the utilities attempt to shield themselves from risk and the full effects of competition. The risk belongs with the program administrators and vendors.

NAESCO, ONSITE SYCOM and NJESCO entirely support the comments of the DRA. These comments are supplementary in order to assert that the Legislature mandated $128 million for new programs and the production of more environmental benefits than the old standard offer programs.

There is no justification in either the Act or the record for lost revenue recovery. The utilities receive tangible and intangible benefits from participating as a competitive provider of products and services.

An ISA offers clear benefits over utility administration, such as delivery of uniform statewide programs, more effective use of marketing dollars in unified marketing and is more efficient and economical. The Utilities/NRDC Stipulation conceded that uniform statewide programs are more efficient, but haven't addressed unified marketing campaigns. Every major advertiser in New Jersey uses unified marketing campaigns yet the utilities have seven approaches. NAESCO,

ONSITE SYCOM and NJESCO do not object to the utility administration of the energy efficiency programs, but object to the implementation scheme proposed in the utility stipulation. They suggest a joint venture model like Mass-Save and RISE.

The Utilities/NRDC Stipulation is designed to maximize money flowing to the utilities through uncapped administration costs, incentives, lost revenues, uncoordinated marketing to promote individual utility brand names, and use of program funds to establish their energy services affiliates that threaten legitimate competition in some markets.

The Advisory Committee should represent the full spectrum of participants. Program design should be decided by the Advisory Committee. Each stipulation proposed a process that will take the balance of the year to complete, the difference between the two stipulations is that the Utilities/NRDC Stipulation addresses specific technology niches, but offers no demonstration that better satisfies the legislative mandate. The Xenergy study said it is more cost effective, but they are designed and operated by National Energy Efficiency Project (NEEP). According to testimony of utility witnesses in this case, these programs were assigned to NEEP on a non-competitive basis. The two sets of programs proposed differ by incentive structure, assignment, and allocation of performance risk. The DRA Stipulation allows vendors to be paid only for delivered results extended to a whole set of programs and promotes competition in every program. The Legislature mandated that any new programs demonstrate a lower cost/kWh than standard offer. The utilities disagree because this results in a clear performance standard and therefore performance risk. The Board should limit its approval to programs where clear metrics exist and move gradually on other programs.

Under the Utilities/NRDC Stipulation, the utilities would obtain full compensation of costs and incentives without linkage to energy savings because market transformation takes 2-3 years to deliver results. Therefore, there is no immediate proof of savings. Utilities and non-profits should step aside and let companies that will take performance risk deliver the programs.

The DRA Intervenors introduced ample evidence of studies commissioned by the utilities that document the benchmark environmental benefits of standard offer programs, which the utilities tried to have excluded as irrelevant. The DRA Stipulation outlines procedures for measuring environmental benefits.

The DRA Stipulation encourages competitiveness and multiple-vendor awards for low income programs. Lost opportunities are addressed by both Stipulations indirectly, however, the DRA stipulation attempts to Stimulate the marketplace to propose new approaches. Market barriers are also addressed by both stipulations indirectly, but the DRA Stipulation emphasizes competitive market mechanisms. They urge the Board to approve the DRA Stipulation.

5. RECO

The Utilities/NRDC Stipulation resolves the four-year funding level, program administration and determines the programs for all the utilities. However, RECO is not a party to and did not sign the stipulation. It is not a settlement and cannot, therefore, bind RECO. RECO does not object to a collaborative process to develop similar program categories nor to administration, but only to the funding provisions for RECO. With respect to RECO's energy efficiency and renewable energy ("EE&R") funding obligations, it is not a settlement among adverse parties and cannot be used in

any way for Board decision-making regarding RECO. The increase for RECO is disproportionately larger than for the signatories' increases as compared to 1998 collections. In the absence of a voluntary proposal, the Board must adopt RECO's filed budget of $260,200 for EE&R supported in the record or RECO's voluntary proposal of $534,000, set forth in its comments. The current regulatory scheme did not anticipate an SBC increase during the transition period and any increase to RECO's EE&R funding would be uncollectable and result in future rate increases. The utility stipulation would cause an additional $4.059 million deferral over the 4-year transition and an additional rate impact of 3% in 2004. RECO is willing to incur the same increase as other utilities, which would result in total statewide funding of $420 million in four years not $423 million. If the Board still wants $423 million, it should reapportion the difference to the other six utilities that agreed to that number. The stipulation would require RECO to spend $1.9 million in 2003, which is seven times more than its projected average annual collections. RECO asserts that the other electric utilities increases are only 1.5 times compared to 3.6 times for RECO.

The Board has other policies from the Act that it must balance with the CRA proceeding such as maintaining sustained lower electric rates, continuing recovery of DSM costs, and maintaining electric utilities financial integrity. Any Board decision has to be based on substantial, competent, credible record evidence and be consistent with the Act and relevant Board Orders. The Board must consider RECO's circumstances in determining the energy efficiency and renewable funding requirements for the next four years.

Although courts have found that a non-unanimous stipulation can serve as a fact-finding tool and be approved, there are constraints. The constraints are that there be interest adversity among the parties, the active parties should participate in negotiating, and the non-unanimous parties afforded an opportunity to argue against it. They must have an evidentiary record, and the Board must examine the record and find the stipulation meets the statutory requirements. This stipulation does not meet the adversity criteria for the funding proposed for RECO because RECO was not a party nor does it meet the statutory requirements, because the funding amount is arbitrary and contrary to record evidence.

Mr. Greene of NRDC illustrated how additional program funding could be obtained without increasing the SBC for other electric utilities. However, for RECO, Mr. Greene only found $180,000 per year of available funding from generation related lost revenues. RECO asserts that number is $116,000.

6. DRA

The DRA describes the Utilities/NRDC Stipulation as primarily a continuation of 'business as usual'. The DRA asserts that the funding is insufficient to meet legislated requirements and that it underfunds new energy efficiency and renewable energy programs by $89 million during the first four years. The stipulation provides no legal foundation the funding proposal. Any unspent funds in a given year can only be carried forward once, and is unclear what happens to the funds if they continue to be unspent. The DRA asserts the plan is to use it to offset legacy program costs and that this provides motivation for the utilities to underspend.

The DRA disagrees with the proposal to use any revenues from the potential sale of direct load control programs to third parties to offset program costs. The performance incentive proposal is overly generous and fundamentally flawed because the goals are too low, the incentives are too

high, it lacks the necessary dead zone, where no incentives or penalties accrue, and it lacks penalties. Additionally, DRA asserts this proposal provides incentives for implementing and finalizing CRA programs, which is a requirement under the Act.

The DRA argues that the proposed discontinuation of measurement and verification for GPU legacy programs, but receiving transition payments is outside the record. Nothing in the Act or existing DSM regulations permits such recovery based on estimated lost revenues and it is directly at odds with past Board policy. Additionally, DRA asserts that the Act states that existing DSM commitments cannot be considered a "new" program cost and the stipulation proposes the savings from this discontinuation of measurement and verification would be used for new programs.

The request for lost revenue recovery should be rejected because the Act does not allow it. The requirement in the Act to transition programs to the competitive market is contrary to and unnecessary because the Act mandates new energy efficiency programs. The DRA further argues that the rationale which may have existed, has been destroyed by the new framework of a SBC created by the Act, which is like a tax. Therefore, the State need not buy utility cooperation because they have competitive opportunities now. The DRA notes that previously the NRDC did not support lost revenue recovery.

The existing DSM rules allow lost revenues only for performance programs that were measured and verified with a free rider offset and subject to an earnings test. Now all seven utilities' energy efficiency programs are eligible without the stringent requirements. There are many benefits from energy efficiency programs for a distribution utility so that sales growth will likely continue, resulting in no real lost revenues.

The DRA disputes the argument that natural gas fuel cells are a Class I renewable energy technology under the Act, asserting the Act merely talks about fuel cells with no mention of fuel type. No one technology should receive such an overwhelming proportion of the funding. DRA argues that gas utilities should not fund renewable energy projects at all because the goal is reduction in electricity generated by non-renewable fuels.

The DRA further states that the Act requires 25% of the new program funding be for renewable energy, but the Utilities/NRDC Stipulation only averages 17% per year. The independent statewide administrator that is proposed depends on funding from the utilities and is therefore not independent. Despite the utilities' assertions about program uniformity, there is no real uniformity and too much control is left with the utilities. The Utilities/NRDC Stipulation includes no statewide marketing, which provides an opportunity for the utility to develop brand identification at the ratepayers expense. Based on common sense it is obvious that a single, independent statewide administrator would be less expensive and more efficient.

The DRA asserts that the proposed programs are replete with costly, unnecessary studies. Only two of those proposed are needed, the baseline study and the one to determine a methodology to measure environmental savings. The customer-sited renewable energy program has no specific plan or standards. Additionally, DRA asserts that approximately 20% of the Customer-Sited Clean Energy Generation Program funds are for administration and marketing. The grid supply program should be scrutinized to ensure it supports only renewable technologies as opposed to "clean" technologies, and only those technologies that are not market ready. The third renewable program should just be a part of the other programs as it is merely research, development and training.

Devoting 25% of the renewable energy funds to research & development is excessive and should be capped at 10%.

The proposed ongoing collaborative process is not a statewide group, but an exclusive group of utilities and the NRDC, which has significant power and would use new program funds to pay collaborative consultants. The DRA further asserts that this collaborative group will evaluate performance targets and make recommendations to the Board as to the level of performance incentives. This is self-serving and a clear conflict. The Board should reject the entire collaborative process proposed in the Utilities/NRDC Stipulation.

The minimum requirements for an administrator are better performed by an ISA and would eliminate the need for the Board to police the huge potential conflict, particularly adherance to affiliate relations standards. The Board should reject utility program administration.

The proposal to commence a process to target clean distribution resources to lower transmission and distribution costs and an alternative form of regulation to remove any disincentives to reduce throughput, does not belong in this proceeding, but does accentuate the inherent conflict in utility administration of these programs.

7. Utilities/NRDC

The Utilities and NRDC submitted comments in favor of their CRA Stipulation (Utilities/NRDC Stipulation) on February 24, 2000. They point out that beside themselves, other interested parties signed on to the Stipulation, such as EDF, BP Solarex, AWEA, [illegible]

The Utilities/NRDC Stipulation proposes appropriate funding levels as well as allocations among the utilities, is cognizant of the rate impacts and provides for increasing the funding in the future. Also addressed in the Stipulation are the treatment of past funding commitments and undercollections from prior years in light of the four-year rate cap transition period.

The question of "new program costs" was resolved in order to assure that the Utilities were meeting their spending obligations. Essentially, the new programs start when the current DSM programs end and include any indirect costs. However, direct load control programs will be funded under the SBC through 2003, but not expanded. Further GPU's measurement and verification funding for legacy programs should be discontinued.

Although the Act is silent on lost revenues the Utilities/NRDC Stipulation provides that to the extent the utilities lose transmission and distribution revenues due to the implementation of energy efficiency programs, the Utilities may recover costs through their SBC through 2003. The utilities will forego lost revenues from renewable programs.

With respect to funding, the Utilities/NRDC Stipulation provides for the utilities to continue: (1) administering energy efficiency programs as well as; (2) customer-sited renewable programs, while; (3) an ISA administers grid-supply and market development renewable energy programs. No statewide trust fund is included in (1) and (2) so that the SBC funds are spent within each utility's service territory, but for (3) a trust fund will be utilized.

The electric utilities will fund Grid-Supply and Market Development Programs, which they can use to satisfy their renewable portfolio obligations. Conversely, the gas utilities have no such obligation and thereby no funding responsibility.

The Customer-Sited Program provides for uniform funding statewide and all Class I renewables are eligible for incentives including natural gas fuel cells. Since the Act includes and the market conditions require incentives for natural gas fuel cells they will receive the same level of funding as other Class I renewables.

The Utilities and NRDC point out that the Act requires the Board to both determine the funding level and the programs simultaneously. The Signatories have agreed to a "single set of statewide program plans for energy efficiency (including low income programs) and renewable energy programs for all utilities." The detailed descriptions of the programs are in the Stipulation and include specific strategies to overcome market barriers.

The Signatories will look to phase out load control programs and energy efficiency programs that the market can support on its own. There will also be a residential retrofit program without ratepayer funding. The Utilities/NRDC Stipulation has an evolutionary approach to program design so that lost opportunities can be captured and low income customers can be better served. Thus, the objectives of the Act are best met by the Utilities/NRDC Stipulation.

8. Honeywell DMC

By letters dated February 16 and 24, 2000, Honeywell DMC basically supports the Utilities/NRDC Stipulation, since it provides appropriate funding and allows the Utilities to transition out of the

existing load control programs. However, Honeywell DMC has some suggestions to improve the document. In particular, the low income customers require more attention and funding. Direct services should be provided to residential low income customers to comprehensively identify and implement efficiencies in existing homes.

Another concern of Honeywell DMC is the small to medium-sized businesses in economically distressed areas. They should receive one-on-one treatment similar to the low income residential customers

9. SESCO

By letter dated February 24, 2000, SESCO sent in comments in opposition to the Utilities/NRDC Stipulation and in favor of the DRA Stipulation. SESCO can show that the Utilities/NRDC Stipulation does not comply with the Act, because it results in an inadequate funding level and delivers no measurable savings. Further, it is not supported by the evidence and does not produce environmental benefits. Most importantly, the DRA Stipulation does comply with the law.

SESCO and other ESCOs have submitted the WECC Report which they purport demonstrates the efficacy of their position. The WECC Report analyzed standard offer programs and advances the theory that they provide valuable benefits to ratepayers.

SESCO, therefore, wants the Board to reject the Utilities/NRDC Stipulation and adopt the DRA Stipulation. The DRA Stipulation complies with the Act, is supported by the evidence and will produce energy savings, bill reductions, cleaner air, more jobs and improved cities and economy.

B. Comments on the DRA Stipulation

Comments on this stipulation were submitted by the following parties and are summarized below:

1. NRDC

NRDC compared this stipulation to its own and concluded that the Utilities/NRDC Stipulation would be better for the environment and New Jersey's electric and gas customers.

2. RECO

RECO opposes the DRA Stipulation – as it is not a "settlement" with compromises by adverse parties, but rather a position paper restating litigated positions of [redacted]

years is even harsher than RPA's litigated position that these should be phased in. Either results in a multi-million dollar deferral even before any deferrals from the Board's Summary Order in Docket Nos. EO97070464, EO97070465, and EO97070466 dated July 28, 1999.

The administration and program design are unreasonable and contrary to credible evidence. Regarding administration, the Board should reject attempts to introduce new information after the close of hearings, such as detailed assertions about Vermont's administration efforts and a proposal that they be introduced here; an affidavit from New Jersey Commerce and Economic Growth Commission; the administrative overhead track record of the Office of Sustainable Business. "The Board should deal harshly with such blatant and unrepentant disregard of the rules of administrative practice and principles of fair play."

Regarding programs, the DRA Stipulation ignores the Act's market transformation goal by allocating almost half the energy efficiency funding proposed in this stipulation to standard performance contracts. As RECO stated in its comments on the Utilities/NRDC Stipulation, it does not oppose a collaborative process to develop programs similar to the categories set forth therein, however program design flexibility is necessary.

3. Utilities/NRDC

The Utilities and NRDC submitted comments on February 24, 2000, in opposition to the Stipulation of Settlement filed by the Division of Ratepayer Advocate, dated February 8, 2000. According to the Utilities and NRDC, the DRA Stipulation is not a true settlement of the issues, ignores the mandates of the Act, and should be rejected.

The DRA Stipulation funding level is not phased in with recognition of the time it takes to initiate new programs. It also does not consider the four-year rate freeze. Further, it would break up the existing utility infrastructure and displace utility employees. And while some states have independent administrators running these programs, there is no evidence that such a system is better than a utility run system. The DRA Stipulation includes no incentive to ensure the effectiveness of an ISA, provides an inadequate transition plan, fails to establish baselines, and does not provide for measurement and evaluation, whereas the Utilities/NRDC Stipulation does.

The DRA Stipulation should be rejected because it is not a stipulation of settlement among adversarial parties. The Utilities are the only real adversarial party and they did not sign the DRA Stipulation.

The funding level in the DRA Stipulation ignores the rate cap on the utilities and the Board's ruling on load control programs. It discounts the lost revenues that energy efficiency and renewable measures incur. It eliminates natural gas fuel cells despite the plain language of the Act.

The DRA Stipulation recommends buyouts, buy-downs and public bonding of existing DSM payments, which is not mentioned in the Act. These strategies are impractical due to the sheer number of such projects, the transaction costs involved, and the increase in costs that would be passed along.

Beyond calling for an ISA, the DRA Stipulation provides no plan for its operation. The contention that an ISA would be less expensive than a utility run system is unsupported. Further, it is

impossible to conclude that the idea of using the Office of Sustainable Business (OSB) within the New Jersey Department of Commerce and Economic Development as the ISA would be practical. There are many unanswered questions about the relationship among the Board, the Legislature and OSB, as well as OSB's funding and procurement rules. It is highly unlikely that programs would be implemented in a timely manner using this scenario.

The DRA Stipulation calls for a permanent advisory committee with little Board oversight unless it cannot agree on program design. The members of the advisory committee need not have program design expertise and could have conflict of interest problems. The stipulation does not state who will manage the advisory committee or pay its members.

The DRA Stipulation does not meet the requirements of the Act with respect to environmental benefits, market barriers, lost opportunities and affordability for low income customers. The description of the concepts proposed is sketchy at best and does not constitute a program plan. Therefore, the Board cannot assure that the ratepayer funds would be spent prudently. The Act calls for a competitive marketplace, whereas, the DRA Stipulation focuses on acquiring energy savings and paying for technologies. Also ignored are strategic marketing efforts, updating industry standards and coordinating program activities and effects with national and state building energy codes, and appliance and equipment standards.

Contrary to the DRA Stipulation position on the Residential Audit–Based Retrofit program of replacing existing equipment with more energy efficient technology the Utilities/NRDC Stipulation has lost opportunity programs that capture energy efficiency improvements when customers build or remodel homes or replace failed equipment with new. The DRA Stipulation provides low income customers with an audit and energy savings measures installed, whereas the Utilities/NRDC Stipulation has a range of programs to make energy bills affordable, including installing all cost-effective measures, energy education, bill counseling and incentives to reduce bill arrearages.

The proposal to allocate 45% of the funding to pay-for-savings by the DRA Stipulation just continues programs that the Act considers capable of being eliminated because they can be delivered by the marketplace. New program funds are to be spent on programs that capture lost opportunities or transform markets. Further, a transition to new programs is not provided, and there is no baseline from which to measure program impacts and energy savings. Also ignored are numerous regional and national efforts for energy efficiency and environmental improvement.

Therefore, the DRA Stipulation is not a true settlement among adverse parties or in compliance with the Act. The Board should reject this Stipulation.

4. DRA

To achieve the objectives of the Act, the Board should adopt the DRA Stipulation, which fully funds both energy efficiency and renewable energy and supports transitioning energy efficiency programs to the competitive market, such as the auctioning of the direct load control programs. Incentives for any administrator should be capped at 5% and the Board should adopt the performance incentive/penalty proposal in the DRA Stipulation.

A truly independent administrator should administer renewable funds placed in a trust fund. If any of the programs in the other stipulation are approved any review necessary should be done by the

Advisory Committee proposed in the DRA Stipulation. A cap on administrative costs similar to other states' 5% is proposed along with program distinctions between market ready renewable technologies and emerging technologies. The former should be encouraged through the RPS not supported by the SBC. The proposed Advisory Committee is a much more open process than the collaborative group.

VI. DISCUSSION AND CONCLUSIONS

A. Funding Issues

1. Calculation of total collections

To determine the funding level for new energy efficiency and Class I renewable energy programs, the amount of collections must first be established. This will enable calculation of the 50% that the Act provides be committed to energy efficiency and renewable energy programs. The level of SBC collections asserted by both groups of stipulating parties, as of the date of the Act, is approximately $256 million. The basis for this number is the utilities' response to the Board's June 17, 1999 Order. However, the Board has determined that actual collections were substantially lower than that. As discussed in further detail below, actual collections amounted to approximately $215 million.

The $256 million asserted by all the parties as the total collections is not stated in the Act, and was calculated on the basis of several assumptions, which are discussed below and some of which the Board finds do not comport with its interpretation of the Act. This number must be based on a full year of collections, and not a theoretical collection amount, in order to comply with the Act's implicit language that CRA funding should be comprised of no less than 50% of the actual amount collected by the gas and electric utilities. Actual collections are determined by multiplying the applicable rate(s) in effect for that full year by the utility's sales during that year. The most recent full year of data prior to February 9, 1999 was for 1998. Using the 1998 sales, which is the same time period used in the utilities' calculation, and the rates in effect to collect demand side management program costs during 1998, the Board FINDS the actual collections were $215 million.

The different results were reached because some utilities did not have the same rate in effect for all of 1998, or had a much lower rate in effect than was assumed in the utilities' calculations set forth in the responses to the June 17, 1999 Order. The difference between the $256 million and the $215 million results from: NJNG's rate from 1/7/98 through 7/7/99 was $.0 per therm; RECO's rate from 1/1/98 through 6/18/98 was - $0.002293, and on 6/19/98 was increased to $0.000031 through 7/31/99, and additionally had some base rate collections; PSE&G's electric rate was $.0007135 per kwh from 1/1/97 through April 2, 1998, and on April 3, 1998 was increased to $.00434 per kwh through 8/1/99; and its gas rate was $.002895 per therm from 1/1/98 through 2/19/98, $.004577 per therm through 11/3/98, and $.004372 per therm from 11/4/98 through 7/31/00. The rates used by each of the abovementioned companies to arrive at the $256 million are $0.35 per therm for New Jersey Natural Gas Company, $0.000031 per kwh for Rockland Electric Company, $.00434 per kwh electric rate for PSE&G and $.004372 per therm gas rate. Therefore, based on actual collections, the Board FINDS that the CRA-SBC collections as of February 9, 1999 were $215 million as outlined in the chart on the following page. Assumptions made on rates for GPU, Conectiv, E'Town and SJG comport with the actual rates in effect.

	RATE	SALES/OUTPUT	REVENUES
Conectiv			
Base Rate Collections	N/A	N/A	$4,800,000
Energy Clause Collection	N/A	N/A	N/A
E'Town			
Base Rate Collections	N/A	N/A	$1,450,000
Energy Clause Collection	N/A	N/A	N/A
GPU			
Base Rate Collections	N/A	N/A	N/A
Energy Clause Collection	0.002869	17,792,192,402	$51,045,800
NJN			
Base Rate Collections	N/A	N/A	N/A
Energy Clause Collection			
01/07/98 – 12/31/98[13]	0.00	424,242,424	$0
PSE&G Electric			
Base Rate Collections	N/A	N/A	N/A
Energy Clause Collection		42,638,000,000	
01/01/98 – 04/02/98	0.0007135	10,659,500,000	$ 7,605,553
04/03/98 – 12/31/98[13]	0.0043402	31,978,500,000	$138,793,086
Total			$146,398,639
PSE&G Gas			
Base Rate Collections	N/A	N/A	N/A
Energy Clause Collection		2,254,760,000	
01/01/98 - 02/19/98	0.002895	308,871,233	$ 894,182
02/20/98 – 11/03/98	0.004577	1,655,549,808	$7,577,451
11/04/98 –12/31/98[13]	0.004372	290,338,959	$1,269,362
Total			$9,740,996
RECO			
Base Rate Collections	N/A	N/A	$2,537,062
Energy Clause Collection		1,353,821,772	
01/01/98 – 06/18/98	- 0.002293	626,838,026	- $1,437,340
06/19/98 –12/31/98[13]	0.0000310	726,983,746	$22,536
Total			$1,122,259
SJG			
Base Rate Collections	N/A	N/A	N/A
Energy Clause Collection	0.0011	480,431,818	$528,475
Total Actual Collections			$215,086,168

[13] The actual time period the rate was in effect may extend beyond 1998, but only the relevant portion in 1998 is noted.

2. Proposed statewide funding level

A broad range of interpretations of the Act regarding statewide funding levels have been presented to the Board. These interpretations have led to filings calling for funding levels from $66 million to $128 million. However, the Board must balance stabilization of utility rates with achieving the other goals in N.J.S.A.48:3-60(a)(3) of providing cleaner air by locating and developing new sources of renewable energy, and delivering energy efficiency in a competitive marketplace. Accordingly, based on the finding that the actual collections were $215 million, the Board FINDS the minimum annual amount of funding for energy efficiency and renewable energy programs to be $107.5 million.

3. Rate impacts

The Legislature's first enunciated goal for EDECA is to lower the high cost of energy. N.J.A.C. 48:3-50(a)(1). This is the Act's primary policy, and although the Act sets forth numerous other policies, it is important to consider this goal in all other decisions the Board must make in implementing the Act. During the transition, the Board must be vigilant to execute policies that do not exacerbate rate increases at the end of the rate cap. At the funding level proposed by many of the parties as 50% of the $256 million, or $128 million, new program spending, added to existing DSM commitments, would exceed actual collections. Even at the minimum funding level determined by the Board as $107.5 million, there would be minimal rate impacts after the end of the rate freeze. While the DRA states that these programs will result in decreased load, therefore negating the effects of any increased rates, the Board believes that this will only protect customers who have these technologies installed, while others without these load-reducing technologies will be affected by the rate increases.

In order to balance these potentially competing policies in EDECA of minimizing rate impacts and providing funding for energy efficiency and renewable energy programs, along with the Board's longstanding responsibility regarding utility rates, the Board has examined the rate impact analyses submitted in response to the August 16, 2000 Order and other evidence relevant to collection levels. The rate impact analyses submitted by each utility demonstrated the rate impact of both proposed stipulations, as follows, and in accordance with formulas and assumptions set forth in the Order.

Rate change associated with deferred balances from CRA funding:

	Utility/NRDC Stipulation	DRA Stipulation
RECO	3.96%	7.24%
Conectiv (w Beginning balance)	-0.13%	1.89%
Conectiv (w/o Beginning balance)	0.81%	2.87%
GPU	-1.13%	-1.13%
PSE&G electric	0.58%	3.01%
SJG	1.10%	1.78%
E'Town(w/Beginning balance)	0.91%	0.89%
E'Town(w/o Beginning balance)	0.91%	0.89%
PSE&G gas	3.23%	2.41%
NJN	0.75%	0.75%

Under the plan constructed by the Board, rate impacts as estimated under the Utilities/NRDC Stipulation will be further mitigated, as will be discussed below.

4. Funding level conclusions

The Board has DETERMINED that in order to mitigate the rate impacts that would result from the DRA Stipulation's funding levels, which are even greater than the rate impacts from the Utilities/NRDC Stipulation for the majority of utilities, the Board must adopt funding levels that are somewhat lower. The Board has DETERMINED that the minimum funding level would be $107.5 million. This funding level, while lower than that proposed in the DRA Stipulation, still comports with the Act's requirement that 50% of the CRA-SBC collections be used for these new programs. Moreover, the Board FINDS that the funding level should be increased beyond the minimum required amount to provide the maximum funding possible, while also mitigating rate increases. In addition, the Board FINDS that the funding be set initially only for three years, allowing the Board to address the fourth year's funding level after the end of the rate freeze period that is currently in place for the electric utilities.

Therefore, the funding levels being adopted herein by the Board are $115 million in 2001, $119.326 million in 2002, and $124.126 million in 2003, for a total of $358.452 million through 2003.[14] This amount is $35.952 million more than the statutory requirement of 50% of the total $215 million being collected as of February 9, 1999, which would total $322.5 million over the three years. Although the Board is only specifying the funding levels for the first three years, the fourth year funding level will be established after the rate cap is lifted. There will also be another four years of funding following a second Comprehensive Resource Analysis, set by the Board to comply with the minimum eight years of CRA in the Act. Additionally, the Board recognizes the delay in completing the CRA Proceeding and will apply $15 million that might have been spent in 2000, to the fourth year of funding, over and above the fourth year's funding, to be determined by the Board.

The Board FINDS that the Conectiv and GPU overcollection amounts resulting either from DSM historically, or CRA, will be applied to offset the CRA deferrals in order to offset the associated rate impacts, making them 0%. Any overcollection not exhausted by the CRA deferrals will be applied to offset other deferred balances.

5. Funding allocation
   a. Renewable energy and energy efficiency

While the two groups of stipulating parties have disagreed on the overall level of funding for each of the initial four years of the CRA, they have also disagreed, as a practical matter, over the level of funding that should be allocated to energy efficiency versus Class I renewable energy programs. From a philosophical perspective, both stipulations supported the statutory requirement of 25% of

[14] This adjustment up from $107.5 million also reflects the Board's recognition that adjusting the annual calculation of collections to a time period that ends more proximate to the effective date of the Act (or February 1, 1998 through January 31, 1999) would have resulted in a collection amount of $230 million, not $215 million. However, all of the parties interpreted the Act to require a 1998 annual calculation, an interpretation with which the Board agrees. Yet by establishing a minimum threshold, the Legislature encouraged Board discretion in adjusting beyond that maximum as we have performed here.

the funding being allocated to renewable energy, as indicated by the language in the Utilities/NRDC Stipulation stating that each administrator is responsible for ensuring that 25% of the funding be allocated to renewable energy as an average over the eight years with flexibility to spend up to the 25% in the early years if demand requires it. However, the DRA Stipulation allocated the 25% immediately on the assumption that the renewable energy market is currently in a position to use this level of funding, while its opposing stipulation assumes this market will need time to mature before it could use the full 25% of funding.

The Board FINDS that the proposal in the DRA Stipulation more accurately reflects EDECA in this regard, and ADOPTS the allocation of the statewide funding between Class I renewable energy programs and energy efficiency as 25% and 75%, respectively, as set forth in EDECA. Although there have been arguments on both sides as to the types of programs that are currently in a position to need and use the funding in the short term, the Board FINDS that there is no real evidence to show that funding should be held back from any particular program. Allowing the market to determine the actual funding requirement is most appropriate.

b. Allocation of funding among the utilities
   i. Statewide/Parity

The next step in determining the funding levels is to allocate the statewide funding level to each utility. The two proposed stipulations differ conceptually on how this should be done. The DRA Stipulation proposes that the statewide level be divided between the electric and gas utilities based on the amount of gas revenues and electric revenues. The DRA Stipulation further proposes the next level of allocation be based on the same rate for each electric and gas utility. The allocation for the electric utilities would solely fund renewable programs. In this way, the DRA's recommendations attempt to achieve parity among the utilities. However, the existing situation is such that each utility's rates were unbundled as part of EDECA, and at least for the electric utilities, these rates must remain fixed until the end of the transition period. Each utility is in a unique situation with regard to the CRA portion of the current SBC collection rate, and the level of continuing recoverable expenses already included in that rate. As some parties have argued, those utilities, which have historically pursued energy efficiency savings aggressively under the Board's rules, could be penalized by instituting parity on a prospective basis. The Board FINDS that it is appropriate at this time, given the aforementioned, to accept the allocation methodology for each utility as proposed in the Utilities/NRDC Stipulation, with modifications for the increase in funding ordered by the Board for 2001, and based on RECO's allocation as discussed in detail below, because these are proportions that each utility finds acceptable under its own unique situation. Additionally, all of the utilities that have the lowest CRA-SBC rates have agreed to increase their spending, helping to move toward parity.

It should be noted that the Utilities/NRDC Stipulation, having been signed by all the utilities except RECO, assigned a spending level to RECO without its concurrence. The impact to RECO's rates resulting from this allocation would be the highest of any of the utilities. To address the excessive rate impact for Rockland Electric Company relative to the other electric utilities as demonstrated in the chart above, the Board FINDS that RECO's proposal for an annual spending level of $534,000 as proposed in its February 10, 2000 comments, is a fair allocation. This amount results in a reduced rate impact for RECO as compared to either the Utilities/NRDC Stipulation or the DRA Stipulation. The $7 million increase in 2001 and the remaining $566,000 from RECO's original allocation for 2001 in the Utilities/NRDC Stipulation, will be allocated among the other six utilities

so that their total allocation will be as follows: PSE&G electric $43.045 million, PSE&G gas $20.773 million, GPU $32.338 million, Conectiv $8.138 million, E'Town $3.962 million, SJG $2.247 million, NJN $3.962 million and RECO $0.534 million.

Recalculation of CRA allocation

($millions)

Utility	Stip-2001	New 2001	Stip-2002	New-2002	Stip-2003	New-2003
PS-elec	40.200	43.045	43.100	43.285	43.200	43.385
PS-gas	19.400	20.773	21.900	21.989	21.800	21.889
GPU	30.200	32.338	32.700	32.839	34.800	34.939
Conectiv	7.600	8.138	9.800	9.835	11.400	11.435
Etown	3.700	3.962	4.000	4.017	4.200	4.217
SJG	2.100	2.247	2.800	2.810	3.500	3.510
NJN	3.700	3.962	4.000	4.017	4.200	4.217
RECO	1.100	0.534	1.700	0.534	1.900	0.534
Total	108.000	115.000	120.000	119.326	125.000	124.126

The difference in funding for 2002 and 2003 versus funding as proposed in the Utilities/NRDC Stipulation will only be partially allocated to the other utilities, as shown above. The Board DIRECTS that the remaining difference of $0.674 million in 2002 and $0.874 million in 2003 be eliminated from the proposed statewide funding level for 2002 and 2003. Based on these allocations, funding levels for 2001-2003 shall be $115 million, $119.326 million, and $124.126 million, respectively.

ii. Renewable energy and energy efficiency allocations

The Board disagrees with the DRA assertion that renewable energy projects should be funded solely by the electric utilities. Although the Class I renewable projects all produce electricity, the Board is not persuaded that this is a sound basis to determine their funding. There are significant environmental benefits from these projects, which will accrue to all New Jerseyans. The environmental benefits are a primary rationale for the importance of funding these projects through a non-bypassable distribution charge in the Societal Benefits Charge. Additionally, EDECA clearly states that the 25% of funding for Class I renewable energy programs should be provided by both the public electric and gas utilities. The Board therefore FINDS that 25% of each utility's total funding for CRA be allocated to Class I renewable energy programs.

The Board FINDS the 25% allocated to each utility for renewable energy programs will be split 40% to grid supply and 60% to customer sited programs in the first year. Thereafter, the funding will be allocated 50% to each category. This initial apportionment recognizes that grid supply projects may not be as mature and in need of funding in the immediate term, but that equal funding will be available going forward.

B. Program Administration

While not expressly required in the Act, the issue of program administration necessarily is a part of this CRA Proceeding. The two major administration issues are: which entity will administer the

programs; and how much money is necessary for the function. The proposal for a trust fund is intertwined with the issue of who will administer the programs. The issue of performance incentives is also tied to administration.

1. Administrative costs

Administrative costs have been a concern throughout this proceeding, and while assertions were made that utility administration has resulted in excessive administrative costs, these assertions remain unsubstantiated. The Utilities/NRDC Stipulation details costs for the renewable energy programs, but has not provided that level of detail for energy efficiency programs. The costs, as noted previously, start out high in the first year, and decline as program start-up reaches completion. The average proposed cost for the renewable energy programs over the four years is slightly more than 5.5%, which closely aligns with the 5% cap discussed in the DRA Stipulation. The Board agrees that programs should be administered effectively and efficiently and, to the greatest extent possible, funding should be spent on actual program incentives and implementation. Therefore, the Board will include in its oversight, stringent monitoring of the administrative costs and herein specifically defines what is to be included as such a cost. The Board DETERMINES that administrative costs shall be defined as the direct labor costs of the administering entity plus overhead. The Board DIRECTS that these costs shall be itemized in the quarterly reports outlined herein. The Board will also track other costs, which could be considered administrative in nature. In its oversight of the energy efficiency and renewable energy programs, the Board will monitor administrative costs to ensure they are not excessive and the Board's consultant will evaluate these costs. Additionally, the administration budget for energy efficiency programs will be evaluated in the compliance filing described further herein.

2. Utilities versus independent statewide administration

Some parties have argued that there is an inherent conflict of interest in the utilities administering the energy efficiency and renewable energy programs, and that it would be more cost-effective for an independent statewide administrator to oversee the funds. Other parties have asserted that there are numerous advantages to utility administration, including existing experience and infrastructure associated with prior programs, and more immediate start-up of programs due to that existing infrastructure. To address these concerns, the Board, in consultation with the DEP, will oversee and monitor the administration of all energy efficiency and renewable energy programs resulting from the CRA Proceeding, while direct administration of the various programs is set forth below.

Administration of the energy efficiency program was not as controversial in these proceedings as was the administration of the renewable energy programs, as evidenced by the settlement proposals. The DRA Stipulation proposed that energy efficiency programs transition from utility administration to an ISA over time. The Utilities/NRDC Stipulation proposed that individual utilities should administer these programs, while there would be joint or coordinated efforts for each program between the utilities and the NRDC, regarding program strategies and evaluation.

Because the Board has ordered the utilities to offer and implement such programs for over 10 years, the infrastructure already exists within each utility for the administration of energy efficiency programs. This existing infrastructure will enable a rapid start up for the new energy efficiency programs. The Board is confident that any concerns regarding real or perceived conflicts of

interest can be addressed through the Board's broad authority over the utilities, and its oversight of the program administration. The Board therefore FINDS that utility administration is appropriate for a period of one year, during which time the Board will retain a consultant to assist in evaluating how best to continue the administration of these programs through the remainder of the 4-year period. At the conclusion of the first year, the Board FINDS that the consultant would have 90 days to submit its recommendations to the Board. Thereafter, the Board FINDS that it would have an additional 60 days to take action on these recommendations. The Board FINDS that utility administration would continue during that evaluation period. The Board HEREBY ADOPTS paragraph 3 of the Utilities/NRDC Stipulation at p. 17 of 20, which sets forth the minimum requirements of any administrator, with one exception. The administrator may not relinquish its role without Board approval.

In addition, the Board shall require quarterly reports from each utility for each program, including at minimum, a detailed breakdown of spending compared to the budget by category, such as administration, incentives, advertising costs, marketing costs, training costs, consultant costs, contractor costs and, the goals and incentive metrics compared to achievements.

Also in accordance with paragraph 3 of the Utilities/NRDC Stipulation, the utilities will administer the Customer Sited Clean Energy Generation Program. However, the Board HEREBY MODIFIES the stipulation to find that administration of the Customer Sited program cannot be relinquished by the utilities without Board approval and administration will be for an interim one year period, during which time the Board will retain a consultant to assist in identifying the appropriate entity to act as ISA thereafter. The consultant will have 90 days to submit its recommendations to the Board, and the Board will have 60 days thereafter to make its determinations.

The interim utility administration of these programs will be performed in accordance with any rules set forth by the Board and will continue until the Board makes its determination. The Board will closely monitor the administration of these programs to ensure equity and timeliness. Additionally, there will be no Renewable Working Group appointed during this interim administration.

As part of the oversight of the Customer Sited program, the Board will impose stringent reporting requirements. Reports will be made to the Board Staff on a quarterly basis and shall at a minimum include the type and size of the technology receiving the incentives, the cost of the system, the cost of installation, the amount of any other incentives, the amount of energy savings provided, the buy down amount and to whom the incentive was paid, application dates, funding reservation dates, inspection dates and the check issue dates. These reports will enable Board Staff to ensure that the concerns expressed by some representatives of the renewable industry that utilities lack the appropriate incentives to administer this program properly can be monitored by Staff and appropriately addressed if the need arises.

The Board Staff, in consultation with DEP Staff, will administer the grid supply program and the market development program. The Board shall appoint an independent advisory group to assist with policy recommendations to the Board on program and technological issues, in order to keep current its understanding of emerging technologies.

Initially, however, the utilities will administer, with the Board's oversight, any parts of the market development program that must be implemented in order for the Customer Sited Clean Energy Generation program to be launched. The utilities shall keep the Board fully apprised regarding

these actions in the interim.

The DRA Stipulation proposes two separate trust funds, one for energy efficiency and one for renewable energy. A major reason the DRA supports a trust fund is based on the argument that it would accommodate greater amounts of dollars flowing to projects in later years when the renewable energy industry has expanded and can utilize greater amounts of funding. The opposing stipulation proposes no trust fund.

Although the Board is not theoretically opposed to the concept of a trust fund, the Board FINDS that it is impractical to establish such a fund for these programs. Other states that have set up trust funds have had the statutory authority to do so, an authority not currently available to the BPU. In addition, the Board DETERMINES that any unspent funds in a trust fund could ultimately be added to the state treasury, and not necessarily be made available for energy efficiency and renewable energy programs.

3. Performance incentives

The Utilities/NRDC Stipulation, in order to encourage the administrator to achieve certain performance levels, proposes goal-driven incentives as part of the administration, with the caveat that poor performance could result in program administration being turned over to some other entity. The DRA Stipulation also supported the concept of performance incentives, but only for a non-government ISA. Some parties have argued that the proposed criteria for incentives in the Utilities/NRDC Stipulation are too easily achieved. The Board has historically supported performance incentives as can be seen in its DSM regulations, in order not only to remove disincentives for utilities to pursue energy efficiency, but to provide an incentive for such pursuits. However, the Board had stringent performance requirements associated with eligibility to earn incentives. Incentives could only be earned for performance-based programs under the DSM regulations, which meant that the actual energy savings had to be measured and monitored. The Board FINDS that the proposal in the Utilities/NRDC Stipulation is not based on performance results but rather on implementation milestones. However, the Board DETERMINES it would be inappropriate to adopt the performance incentives as proposed.

C. Program Design

1. Energy efficiency

With one exception, the DRA Stipulation and the Utilities/NRDC Stipulation are similar in their energy efficiency programs with regard to fundamental structure. That exception is the pay-for-savings proposal in the DRA Stipulation. These are programs in which the incentive for efficiency improvement is paid based on the measured level of savings. This program type is not included in the Utilities/NRDC Stipulation although both stipulations contain what the DRA Stipulation refers to as pay-for-technology and pay for infrastructure. A pay-for-technology program design is one in which the incentive covers some portion of the incremental cost of the more expensive energy efficient equipment, while pay-for-infrastructure supports infrastructure development.

The standard offer program, which was an option under the existing DSM regulations for a performance program, is an example of the pay-for-savings approach. The Board FINDS that there is no support in the Act requiring continuation of this type of program. The Board DETERMINES that the intent of the Act is to establish a funding requirement for new programs,

which produce additional savings beyond any old programs that may be continuing to receive funding. Energy load is reduced through improvements in energy efficiency and through the replacement of traditional energy supply with the use of renewable energy programs, hence assisting in reducing air emissions and producing environmental benefits. Additionally, based on our experience with the standard offer, the Board FINDS that it is more expensive to pay for the value of energy savings than it is to provide incentives for the technology directly. In addition to which, these technologies have already been proven to save energy, so that the energy savings are assured through pay-for-technology programs.

For the foregoing reasons, the Board HEREBY ADOPTS the energy efficiency programs as set forth in the Utilities/NRDC Stipulation and DIRECTS the utilities to file as part of its compliance filing described therein, detailed proposed budgets for each of these programs, including a breakdown of administration, advertising, incentives, contractor costs, and training within 30 days of the date of this Order for Board approval. The Board FINDS that the utilities must begin implementation of the energy efficiency programs at least within 60 days of the date of this Order. The Board wishes to make clear that it expects a diversity of technologies to be supported that address all market sectors. Additionally, the Board Staff will continue to work with DEP to develop appropriate environmental goals for these programs, thus ensuring that energy savings are maximized.

2. Renewable Energy
   a. Customer sited renewables programs

The two stipulations significantly narrow the gap between the positions of various parties on this issue. Both propose a buy down program for customer-sited projects, which would provide an incentive to offset the cost of a renewable energy project designed to supply some or all of the customer's electricity. The differences between the two are small, relative to the similarities.

The basis for the virtual agreement by all the parties on this type of program design is because it addresses one of the most significant market barriers to customer's embracing renewable technologies, that of first cost. Renewable technologies cannot currently compete with traditional generation on a cost basis. However, because these technologies can provide very significant environmental benefits and reduce the State's dependence on fossil fuels, it is important that the State assist these technologies to develop market share.

Customers are used to buying energy, but are unfamiliar generally with the fact that they are also purchasing capacity, distribution and transmission. A renewable energy technology sited at the customer's facility and designed to meet that customer's individual electricity needs is, in fact, distributed generation and requires a different perspective. This educational issue is also a market barrier, which needs to be addressed.

Buying down the initial cost of the equipment and installation of a renewable distributed generation technology allows these emerging technologies to compete with traditional electricity supply. Reducing the price of the distributed generation allows renewable energy to more closely track the price a customer pays for traditional supply, and therefore addresses a significant market barrier. This meets several goals of the Act, providing significant environmental benefits to New Jersey, and creating a market for renewable energy technologies that can eventually compete with traditional energy supply methods without subsidy.

The Act requires that the Board, as a result of the CRA, initiate a program, which provides financial incentives for Class I renewable projects considering, among other things, market barriers and environmental benefits. A customer-sited buy down program for renewable energy projects has the support of all of the parties to this case and can meet the Board's legislative mandate. This program, under both stipulations, targets the technologies (photovoltaics, fuel cells and small wind turbine systems) that DEP recommends as those distributive technologies with the highest environmental benefits. Both stipulations provide incentives that decline with each discrete block of power provided; however, under the DRA Stipulation the blocks are smaller, and incentives decline more rapidly. The differences in eligible technologies are sustainable biomass is supported only by the Utilities/NRDC Stipulation, solar thermal electric generation is supported only by the DRA Stipulation, while both support the other technologies. Each stipulation proposes a maximum incentive based on a percent of system cost, for the DRA Stipulation, this is 60%, and for the Utilities/NRDC Stipulation, it starts at 60% and declines with each block ultimately to 30%. Both stipulations also propose a cap to protect against any one technology using all the funding. In the Utilities/NRDC Stipulation no one technology can receive more than 50% of the funding, while the DRA Stipulation has its cap based on the size of the project with 50% for small, 25% for medium and 25% for large. Additionally, the DRA Stipulation proposes a cap on the maximum project size.

The Act defines Class I renewable energy as electricity produced by solar, photovoltaic, wind, fuel cells, or geothermal technologies, wave or tidal action, and landfill gas or a sustainably fueled biomass facility. Although solar thermal electric generation is covered by this definition, the DEP advises that the technology is pre-emerging and should not be supported under this program at this time. Sustainable biomass is supported by the DEP recommendation provided it meets particular criteria, and that initially, funding be limited to small-scale sustainable gasifiers or digester technologies operated at the farm-scale level for farm generated sustainable biomass.

Limiting the incentive to a percentage of the cost of the system addresses the concept that emerging technologies should be supported with these incentives to assist in attaining market competitive status in the future. Theoretically, pre-emerging technologies would require more than the maximum 60% proposed by both stipulations, and as technologies mature and become more competitive less incentive would be required. This approach supports the concept of declining maximum incentives and market transformation.

The Board supports development of diverse technologies as a goal of the programs to be determined as part of the CRA proceeding. The Board has endeavored in this Order to make decisions that facilitate this goal. Both stipulations obviously agree with this philosophy, as both propose limits on the amount of funding available for projects, the DRA Stipulation by size, and the Utilities/NRDC Stipulation by technology. The Board must balance this desire for diversity without hindering competition.

For the foregoing reasons, the Board ADOPTS the Customer-Sited Clean Energy Generation Program design set forth in the Utilities/NRDC Stipulation with modifications. The modifications are that this will be implemented within 30 days from the date of this Order, including acceptance of applications, and shall be a full-scale program, not a pilot program as proposed. Applications submitted to the Board under the Interim Order dated December 4, 2000 shall be processed immediately upon adoption of guidelines for interim funding.

b. Grid supply

Both stipulations proposed a competitive incentive program for grid supply renewable energy production, which is also supported by DEP. Grid supply projects are those that supply electricity to the grid, as opposed to those projects, which are designed to meet individual customer needs. The DRA Stipulation additionally proposed a Customer Credit Program, which would provide a direct incentive to customers to buy green power. In accordance with recommendations in both stipulations, the Board FINDS that a direct competitive incentive program, which will provide production credits, is an appropriate mechanism to encourage development of renewable energy projects to provide power to the grid. The Board also FINDS that this type of program can effectively promote competition among technologies and encourage cost effective grid supply technologies. However, the Act also intends to encourage the development of a thriving, diversified renewable energy market. As has been noted by some parties, there are currently some renewable energy technologies, which are less able to compete on the basis of cost than others because they may yet be emerging technologies. For the successful implementation of the full intent of the Act, the Board FINDS that it is appropriate to provide an arena in which grid supply technologies, which may not be able to compete as yet on a cost basis, are not denied the opportunity to prove themselves as a viable alternative to traditional electricity supply. Therefore both cost, and the need to foster diverse technologies will be considered when reviewing project funding. Additionally, the Board will work with DEP to develop environmental goals for this program. The Board does not believe that a customer credit program is appropriate at this time until the effectiveness of the Renewable Portfolio Standards can be determined. The Board may consider other additional mechanisms to foster the development of renewable grid supply as it determines the details of this program. Program details will be issued within sixty days of the date of this Order.

The Board FINDS that as many parties argued, grid supply locations are, by their nature, dependent on the location of the resource. Therefore, the Board DETERMINES that this program will not be bound by utilities' service territories, and the utilities will be appropriately and proportionately billed by the Board for program expenses.

c. Infrastructure development

The Board FINDS that the two stipulations are again similar in intent with regard to such things as infrastructure development, training, and certification for renewable energy programs. Both stipulations support the need for funding for these types of activities. The DRA Stipulation allocates 20% ($6.4 million) of its renewable energy budget to this type of activity while the Utilities/NRDC Stipulation allocates 25% (approximately $1.5 million) in 2000. The Board FINDS that the amount of money proposed in the Utilities/NRDC Stipulation is a more appropriate level of funding for the first year. Additionally, as the Board will be administering this program, adjustments in the level of funding can be made as needed. Therefore, the Board ADOPTS for the first year (2001), the funding in the Utilities/NRDC Stipulation proposed for 2000, which is approximately 5.5% of the revised renewable energy budget, and ADOPTS the program description set forth therein as a guideline. The Board will determine the precise program details as it sees fit. The Board DETERMINES that the funding shall continue to be 5.5% of the annual renewable energy budget for 2002 and 2003 unless the Administrator finds a modification to be appropriate. Additionally, the Board is allocating $100,000 of that 5.5% to develop an environmental tracking system through PJM.

3. Renewable Portfolio Standards

Under EDECA, the Renewable Portfolio Standards (RPS) require electric suppliers to have a certain percentage of its power supplied by Class I and Class II renewable energy. While not a part of the Act's description of CRA, RPS was raised within this proceeding as an issue that should be addressed. Some parties have argued that the RPS should not be supported by SBC funding. The Board FINDS that fulfilling the requirement for RPS may be difficult initially for suppliers because of the current shortage of developed renewable energy supply, and that in the interest of providing cleaner air for New Jersey citizens, the prudent response is to allow CRA-SBC funding to contribute to fulfilling the RPS standards. The Board will reconsider this decision after one year and determine if it remains appropriate. Additionally, the Board will address the details of eligibility for RPS in its final order adopting those standards.

D. Lost revenue recovery

The two stipulations differ substantially on this issue. The DRA Stipulation allows no lost revenue recovery for new programs, while the Utilities/NRDC Stipulation proposes to allow lost revenue recovery for new energy efficiency programs, but not for renewable energy programs. The recovery also would not count as a new program cost and would only be in effect through 2003. The litigated positions of the parties to the Utilities/NRDC Stipulation demonstrate some significant compromise on this issue already, as NRDC was originally opposed to this concept.

The Board therefore ADOPTS the proposal in the Utilities/NRDC Stipulation as a reasonable compromise regarding lost revenue recovery with the caveat that if program administration is taken from the utilities, the Board may wish to reconsider this issue, prospectively. Lost revenue recovery and incentives were allowed under the DSM regulations only for programs with measured and verified savings. The amount of fixed cost revenue erosion resulting from energy efficiency measures can be significant and it is therefore important for the calculation of these costs to be accurate. This need for accuracy is the reason the Board was historically unwilling to allow the recovery of lost revenues for programs that did not have verified, measured savings. The Board also FINDS that, under the Utilities/NRDC Stipulation, the program evaluation plans for determining energy savings have not yet been submitted to the Board, therefore, the basis for determining the collection of lost revenues for the new energy efficiency programs must still be approved by the Board.

The Board ADOPTS the proposal in the Utilities/NRDC Stipulation for continuation of lost revenue recovery for legacy programs and GPU's transition payment in recognition of the high cost of continued measurement. However, the Board wishes to ensure that continued lost revenue recovery is based on accurate savings data. Measurement and monitoring of GPU's performance-based legacy programs has been ongoing, since 1993 under GPU's Board approved DSM plan and a significant amount of data has been collected.

Therefore, the Board is willing to allow the use of this data to predict the savings for lost revenue recovery going forward in exchange for the reduced transition payment of 90% for 2001. To compensate for concerns about accuracy and to protect ratepayers from paying too much, the Board DIRECTS that any continued recovery beyond 2001 for legacy program lost revenues shall decline to 80% in 2002 and 70% in 2003. However, the Board expects a base rate case filing prior to the end of the transition period, at which time lost revenues are appropriately reset to zero. If there is no base rate case in 2003, the Board shall reconsider the eligibility of legacy lost revenue recovery, prospectively.

E. Findings

Based on the foregoing, the Board HEREBY FINDS AND DIRECTS as follows:

1) The CRA-SBC statewide collections from electric and gas utilities as of February 9, 1999 are $215 million.

2) Consistent with the various goals and the Act's requirement that at least 50% of the CRA-SBC collections be used for new programs, the statewide funding levels being adopted herein are $115 million in 2001, $119.326 million in 2002, and $124.126 million in 2003, for a total of $358.452 million through 2003.

3) The funding is set only for three years, allowing the Board to address the fourth year's funding level after the end of the rate freeze period that is currently in place for the electric utilities. The fourth year funding level will be established after the rate cap has ended. There will also be another four years of funding determined by the Board to comply with the minimum eight years of CRA in the Act.

4) In recognition of the delay in completing the CRA Proceeding, $15 million will be applied to the fourth year of funding, over and above the level to be determined by the Board.

5) The Conectiv and GPU DSM-CRA overcollection will be applied to offset the CRA deferral in order to bring the associated rate impact up to zero. Any such overcollection over and above that level will be applied to offset the BGS deferred balance. If no such deferral exists at the end of the transition period, any DSM-CRA related overrecoveries shall be applied to CRA in a manner to be determined by the Board at that time.

6) As set forth in EDECA, the allocation of the statewide funding between Class I renewable energy programs and energy efficiency is 25% and 75%, respectively.

7) The allocation for each utility in millions for each of the three years is:

Utility	2001	2002	2003
PS-electric	43.045	43.285	43.385
PS-gas	20.773	21.989	21.889
GPU	32.338	32.839	34.939
Conectiv	8.138	9.835	11.435
Etown	3.962	4.017	4.217
SJG	2.247	2.810	3.510
NJN	3.962	4.017	4.217
RECO	0.534	0.534	0.534
Total	115.000	119.326	124.126

8) In accordance with EDECA, annually 25% of each utility's total funding for CRA for the program year will be allocated to Class I renewable energy programs.

9) Each utility's allocation for renewable energy programs will be split 40% to grid supply and 60% to customer sited programs in the first year. Thereafter, the funding will be allocated on a 50%/50% basis.

10) Administrative costs shall be defined as the direct labor costs of the administering entity plus overhead and these costs shall be separately reported in the quarterly reports outlined herein. Other costs, that could be considered administrative in nature, shall also be tracked. Administrative costs shall be monitored to ensure they are not excessive and shall be evaluated by the Board's consultant. The administration budget for energy efficiency programs shall be detailed in the compliance filing for evaluation.

11) The Board, in consultation with the DEP, shall oversee and monitor the administration of all energy efficiency and renewable energy programs resulting from the CRA Proceeding.

12) The utilities shall directly administer the energy efficiency programs for a period of one year. The Board shall retain a consultant to assist in evaluating how best to continue the administration of these programs through the remainder of the 4-year period. The consultant shall issue a report within 90 days of the conclusion of the first year. Thereafter, the Board would have an additional 60 days to take action on the report. Utility administration will continue during that evaluation period. The utilities shall comply with paragraph 3 of the Utilities/NRDC Stipulation at p. 17 of 20, which sets forth the minimum requirements of any administrator, except that the administrator may not relinquish its role without Board approval. The utilities shall begin implementation within at least 60 days of the date of this Order.

13) Consistent quarterly reports from each utility shall be submitted for each energy efficiency program, including at least a detailed breakdown of spending compared to the budget by category such as, administration, incentives, advertising costs, marketing costs, training costs, consultant costs, contractor costs and, the goals and incentive metrics compared to achievements.

14) Also, in accordance with paragraph 3 of the Utilities/NRDC Stipulation, the utilities shall administer the Customer Sited Clean Energy Generation Program except that administration of the Customer sited program cannot be relinquished by the utilities without Board approval and shall be for an interim one year period during which time the Board shall retain a consultant to assist in identifying an entity to act as ISA thereafter. The utilities shall begin implementation within at least 30 days of the date of this Order. The consultant shall have 90 days to submit its recommendations to the Board, and thereafter, the Board shall have 60 days to make its determinations.

15) The interim utility administration of these programs shall be performed in accordance with any rules set forth by the Board and shall continue until the Board makes its determination. The Board shall closely monitor the administration of these programs to ensure equity and timeliness. Additionally, there shall be no Renewable Working Group appointed during this interim administration.

16) As part of the oversight of the Customer Sited program, there shall be stringent reporting to Board Staff on a quarterly basis, which at a minimum shall include the type and size of the technology, the cost of the system, the cost of installation, the amount of any other incentives, the amount of energy savings provided, the buy down amount and to whom the incentive was paid, along with reservation dates, application dates, inspection dates and the check issue dates.

17) The Board in consultation with DEP shall administer the grid supply program and the market development program. An independent advisory group shall assist with policy recommendations to the Board on program and technological issues.

18) Initially the utilities shall administer, with the Board's oversight, any parts of the market development program that must be implemented in order for the Customer Sited Clean Energy Generation program to be launched. The utilities shall keep the Board fully apprised regarding these actions in the interim.

19) There shall be no trust fund.

20) The proposed performance incentives are denied.

21) There is no support in the Act requiring continuation of pay-for-savings type programs only to determine the funding for programs with environmental benefits above and beyond those provided by standard offer and similar programs. The intent of this language simply establishes a funding requirement for new programs, which produce additional savings beyond any old programs that may be continuing to receive funding. Improvements in energy efficiency and the use of renewable energy both reduce the use of traditional energy supply and hence new energy efficiency and renewable energy programs reduce air emissions and produce environmental benefits.

22) The energy efficiency programs shall be as set forth in the Utilities/NRDC Stipulation. The utilities shall file within 30 days of the date of this Order, as part of its compliance filing, detailed proposed budgets for each of these programs, including a breakdown of administration, advertising, incentives, contractor costs, and training for Board Staff approval. Diversity of technologies that address all market sectors is expected to result and environmental goals also need to be achieved through these programs. The Board Staff shall continue to work with DEP to

develop appropriate environmental goals for these programs.

23) The renewable distributed generation program shall be the Customer-Sited Clean Energy Generation Program design set forth in the Utilities/NRDC Stipulation with modifications. The program shall be implemented within 30 days from the date of this Order, including acceptance of applications, and shall be a full-scale program, not a pilot program. Applications submitted to the Board under the Interim Order dated December 4, 2000 shall be processed immediately upon the Board's adoption of guidelines for interim funding.

24) It is appropriate to provide an arena in which grid supply technologies, which may not be able to compete as yet on a cost basis, are not denied the opportunity to prove themselves as a viable alternative to traditional electricity supply. Therefore, both cost, and the need to foster diverse technologies when awarding funding shall be considered. Board Staff shall work with DEP to develop environmental goals for this program. Other additional mechanisms to foster the development of renewable grid supply may be considered in the development of this program. Program details shall be issued by the Board within sixty days of the date of this Order.

25) The grid supply program shall not be bound by utility service territories, and the utilities shall be appropriately and proportionately billed by the Board for program expenses.
26) The amount of money proposed for 2000 in the Utilities/NRDC Stipulation for the market development program shall be the level of funding for the first year and the program description set forth therein as a guideline. Additionally, as the Board shall be administering this program, adjustments can be made as needed. The Board shall determine the precise program details as it sees fit. The funding shall continue to be 5.5% of the annual renewable energy budget for 2002 and 2003 unless the Administrator finds a modification to be appropriate. Allocation of $100,000 shall be included to develop an environmental PJM tracking system.

27) CRA-SBC funding may contribute to fulfilling the RPS standards. The decision may be reconsidered by the Board after one year to determine if it remains

29) The continuation of lost revenue recovery for legacy programs and GPU's transition payment of 90% for 2001 as proposed in the Utilities/NRDC Stipulation, however, any continued recovery beyond 2001 for legacy program lost revenues shall decline to 80% in 2002 and 70% in 2003. If a base rate case is filed prior to the end of the transition period, lost revenues shall be appropriately reset to zero. If there is no base rate case in 2003, the Board shall reconsider the eligibility of legacy lost revenue recovery, prospectively.

DATED: March 9, 2001

BOARD OF PUBLIC UTILITIES
BY:

SIGNED

HERBERT H. TATE
PRESIDENT

SIGNED

FREDERICK F. BUTLER
COMMISSIONER

Having been sworn in as Acting Commissioner on February 13, 2001, I have not had an adequate opportunity to review this matter prior to the Board's March 1, 2001 agenda meeting and I therefore abstain from rendering a decision

SIGNED

CAROL J. MURPHY
ACTING COMMISSIONER

ATTEST:

SIGNED

FRANCES L. SMITH
BOARD SECRETARY

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

ENERGY

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF AN INCREASE IN AND ADJUSTMENTS TO ITS UNBUNDLED RATES AND CHARGES FOR ELECTRIC SERVICE, AND FOR APPROVAL OF OTHER PROPOSED TARIFF REVISIONS IN CONNECTION THEREWITH	)	FINAL ORDER DOCKET NO. ER02080506
IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF ITS DEFERRED BALANCES RELATING TO THE MARKET TRANSITION CHARGE AND SOCIETAL BENEFITS CHARGE	)	DOCKET NO. ER02080507
IN THE MATTER OF THE CONSUMER EDUCATION PROGRAM ON ELECTRIC RATE DISCOUNTS AND ENERGY COMPETITION - JERSEY CENTRAL POWER & LIGHT COMPANY'S VERIFIED PETITION FOR DECLARATORY RULING	)	DOCKET NO. EO02070417
IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF COSTS INCURRED FOR ENVIRONMENTAL REMEDIATION OF MANUFACTURED GAS PLANT SITES AND FOR AN INCREASE IN THE REMEDIATION ADJUSTMENT CLAUSE OF ITS FILED TARIFF IN CONNECTION THEREWITH	)	DOCKET NO. ER02030173
IN THE MATTER OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR INCREASES	)	

IN ITS LEVELIZED ENERGY ADJUSTMENT)
CLAUSE CHARGE AND DEMAND SIDE FACTOR) DOCKET NO. ER95120633

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Final Order memorializes and provides the reasoning for the action taken by the Board of Public Utilities ("BPU" or "Board") in the above captioned matters, by a vote of five Commissioners at its July 25, 2003 public agenda meeting, which action was summarized in the Board's Summary Order dated August 1, 2003. This Final Order supersedes the Board's August 1, 2003 Summary Order.

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I. BACKGROUND AND PROCEDURAL HISTORY

This Order resolves the five above-captioned petitions filed by Jersey Central Power & Light Company ("JCP&L" or "Company"). These include:

1) BPU Docket No. ER02030173, filed on March 13, 2002, seeking a review and a change of rates in the Company's Rate

JCP&L filed a motion to consolidate the first four petitions with the Board on August 1, 2002. These petitions collectively request Board approval of proposed overall increases and/or other adjustments to JCP&L's various unbundled tariff rates and charges for electric service effective for service rendered on and after August 1, 2003. These petitions were transmitted to the Office of Administrative Law ("OAL"), and assigned to Administrative Law Judge ("ALJ") Irene Jones.

Additionally, pursuant to the Board's Order dated July 22, 2002, Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, Dkt. No. ER02050303, et al., an audit was performed on JCP&L's deferred balances, the results of which were placed in the record of the deferred balances case at the OAL.

These four matters now come before the Board on a record developed in hearings before the ALJ. Before considering the record that has been developed on these matters, a brief description of the events leading to these filings is provided below.

On February 9, 1999, the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. ("EDECA" or "Act") was signed into law. Among other things, EDECA required the Board by Order to provide that by no later than August 1, 1999, each electric utility provide retail choice of electric power suppliers for all its customers, N.J.S.A. 48:3-53(a); unbundle its rate schedules, N.J.S.A. 48:3-52(a); reduce its aggregate level of rates for each customer class by no less than five percent, N.J.S.A. 48:3-52(d)(2); provide basic generation service ("BGS") at approved rates for customers who do not choose an alternate power supplier, N.J.S.A. 48:3-52(b); provide approved "shopping credits" to be deducted from the bills of customers who choose an alternate power supplier, N.J.S.A. 48:3-52(b); implement a Societal Benefits Charge to recover the cost of previously approved social, environmental, and demand side management ("DSM") programs, which were included in the utilities' bundled rates, N.J.S.A. 48:3-60(a); and (2) implement a Market Transition Charge to allow each utility the opportunity to recover an approved level of stranded costs, N.J.S.A. 48:3-61.

Prior to the enactment of EDECA, the movement toward energy market competition was already underway. The New Jersey Energy Master Plan Phase I Report, released in March 1995, presented a vision for the State in which energy markets in New Jersey would be guided by market-based principles and competition. Thereafter, after conducting extensive proceedings, on April 30, 1997, the Board issued an Order adopting and releasing a report entitled: Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations, BPU Docket No. EX94120585Y, dated April 30, 1997 ("Final Report," also referred to as the "Green Book"). The Final Report was submitted to the Governor and the Legislature for their consideration. In anticipation of restructuring legislation to be developed and enacted, the Board's April 30, 1997 Order directed each of the State's four investor owned electric utilities to make three filings by July 15, 1997. These filings included a rate unbundling petition, a stranded costs petition, and a restructuring plan.

On July 15, 1997, JCP&L filed verified petitions with the BPU setting forth its unbundling, stranded costs and restructuring proposals. The unbundling and stranded costs petitions were assigned BPU Docket Nos. EO97070458 and EO97070459, respectively, and were transmitted to the OAL and assigned to ALJ Diana C. Sukovich. The restructuring petition was assigned BPU Docket No. EO97070460, and was retained by

the Board. After extensive hearings and briefing, ALJ Sukovich issued an Initial Decision on the unbundling and stranded costs issues on September 4, 1998. Hearings on all four utilities' restructuring petitions were held before the Board (chaired by Commissioner Carmen J. Armenti) in April and May 1998.

On February 11, 1999, shortly after the enactment of EDECA, the Board established guidelines and a schedule for the commencement of settlement negotiations among the parties in JCP&L's restructuring proceedings. Though all parties could not reach a comprehensive settlement, two proposed stipulations of settlement were filed with the BPU in March 1999. One proposed settlement ("Stipulation I") was executed by JCP&L and certain parties. An alternative settlement ("Stipulation II") was executed by the RPA and several other parties. After reviewing the entire evidentiary record, including the proposed settlements and comments of the parties with respect thereto, as well as the requirements of EDECA, the Board issued a Summary Order dated May 24, 1999. In the Matter of Jersey Central Power & Light Company d/b/a GPU Energy - Rate Unbundling, Stranded Cost and Restructuring Filings, BPU Docket Nos. EO97070458, EO97070459, and EO97070460 ("Summary Restructuring Order"). On March 7, 2001, the Board issued its Final Restructuring Order under the same caption. In these two Orders (collectively, "Restructuring Orders"), the BPU modified the ALJ's Initial Decision in light of subsequent developments, and found that the elements of Stipulation I, with significant modifications and clarifications, to address concerns raised by the parties, including the proponents of Stipulation II, provided an appropriate framework for a reasonable resolution to the unbundling, stranded costs and restructuring filings.

The Restructuring Orders directed JCP&L to implement an initial rate reduction of 5% effective August 1, 1999, pursuant to N.J.S.A. 48:3-52(d)(2), and to phase in additional rate reductions in 2000, 2001 and 2002, which exceeded the minimum 10% reduction for the fourth year of the Transition Period required by N.J.S.A. 48:3-52(d) and (j). Specifically, the Board modified the proposed rate reductions included in Stipulation I, to provide for additional phased-in reductions, drecting that the aggregate level of rate reductions be increased to 6% effective August 1, 2000, and further increased to 8% effective August 1, 2001; and that the rates be further decreased effective August 1, 2002, to an aggregate level 11% less than the level of rates in effect as of April 30, 1997. Final Restructuring Order at 91. The Board further directed that the 3% incremental rate reduction during the fourth year of the Transition Period be accomplished by implementing Stipulation I's proposed 5% rate refund provided for in Stipulation I, offset by a 2% increase in the MTC. Id. The Board also concluded that it would be reasonable and appropriate to utilize the 1996 cost of service study ("COSS") for the basis of establishing the level of unbundled distribution rates. (Id. at 93).

The Board further found that recovery of the above-market costs associated with utility power purchase agreements ("PPAs") via the MTC was consistent with N.J.S.A. 48:3-61(a)(2); and recovery of above-market costs associated with NUG contracts, as well as costs associated with NUG contracts buyout payments via the MTC was consistent with N.J.S.A. 48:3-61(a)(3). The Board also concluded that any Levelized Energy Adjustment Clause ("LEAC") over or under-recovery balance, to the extent reasonably incurred, existing as of August 1, 1999, would be considered a restructuring-related cost/credit. The Board found it appropriate for deferred fuel costs to be recovered (or credited back to customers) via the MTC, in accordance with N.J.S.A. 48:3-61(a)(4). (Id. at 97).

The Board established shopping credits at levels higher than contained in Stipulation I, but lower than in Stipulation II, finding that it needed to strike a balance between the level of shopping credits estimated to be needed to stimulate the development of a competitive market and the Act's mandated level of rate reductions. The Board found that, as a matter of law, JCP&L was entitled to full and timely recovery of the prudently and reasonably incurred costs associated with the provision of BGS and utility and NUG PPA costs pursuant to its obligation to provide basic generation service under N.J.S.A. 48:3-57. (Id. at 112). The Board directed that, to the extent these costs, as realized, exceeded the recovery afforded by the regulated rates, JCP&L could defer recovery of the net excess amount of costs and to accumulate in a deferred account, together with interest on the unamortized balances and carry on JCP&L's balance sheet the deferred balances as a regulatory asset. Id. JCP&L was directed to make a filing no later than August 1, 2002, in order to allow the BPU to review and determine the amounts of any over or under-recoveries contained in the deferred accounts as discussed above, as well as to examine the proposed level of all rate components beginning August 1, 2003. (Id. at 102).

On July 22, 2002, the Board directed JCP&L and the other three electric utilities to include certain specific items in their base rate filings, including distribution charges, the other components of their unbundled rates, an accounting for the use of proceeds from the issuance of transition bonds, and the effect of such use on the utility's capital structure and costs underlying the rate of return claimed in the filing. Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, BPU Docket Nos. ER0205303, EO97070461, EO9707462 and EO97070463, dated July 22, 2002. The Board also directed the electric utilities to file their respective deferred balance petitions by August 30, 2002, and to include actual data by months for the first three years of the Transition Period and projected data by months for the last year of the Transition Period, which was to be updated on a monthly basis as it became available. The Board stated that the deferred balances filings would be transmitted to the OAL for hearing, and that the ALJ assigned to each utility's deferred balances case would also preside over that utility's base rate case. The Board anticipated that the base rate and deferred balance cases would be litigated separately and then consolidated for purposes of rendering a single Initial Decision. (Id. at 10-11).

On July 31, 2002, Governor McGreevey convened, by Executive Order 25, a Deferred Balances Task Force to examine "the reasons why the deferred balances were accumulated, what mitigation steps utilities took to reduce deferred balances and how they ought to be addressed to best protect the interest of ratepayers, including an evaluation of the merits of securitizing deferred balances." The task force issued its report on August 30, 2002. On September 6, 2002, the Governor signed into law Senate Bill 869, containing certain modifications to EDECA, which would allow, but not require, the BPU to permit securitization of portions of the utilities' deferred balances, subject to certain conditions being met. N.J.S.A. 48:3-51 and 48:3-62.

On July 29, 2002, the Board issued a Request for Proposal to secure the services of an independent accountant/auditor/consultant to perform audits of all four utilities' deferred balance accounts, transactions and supporting calculations for the Transition Period. Request for Proposal to Perform Audits of the Deferred Balances of New Jersey's Four Electric Utilities, BPU Docket No. EX02060363 and EA02060365. The Board's overall objective was to obtain certified opinions as to whether the utilities' deferred balances were correct and included only those costs that were reasonable, prudently incurred,

accurately calculated, correctly recorded and in compliance with all applicable Board Orders. Regarding prudence of BGS costs, the auditors were directed to determine, at a minimum, whether the utilities pursued a prudent procurement procedure for the acquisition of BGS and whether, when required, they purchased power at reasonable prices consistent with market conditions in the competitive wholesale marketplace and consistent with appropriate hedging techniques. The auditors were also directed to comment on the utilities' mitigation efforts with regard to above-market NUG contract costs during the Transition Period.

On October 2, 2002, Mitchell & Titus, LLP ("M&T") and Barrington-Wellesley Group, Inc. ("BWG") (collectively, "the Auditors") were engaged to perform the audit of JCP&L. The scope of the audit consisted of JCP&L's transactions during the Transition Period, as they impacted the deferred balance accounts. The audit was to be conducted in two phases, with Phase I entailing JCP&L's deferred balances from August 1, 1999 through July 31, 2002 and Phase II entailing deferred balances from August 1, 2002 through July 31, 2003.

Given the regulatory background summarized above, on March 13, 2002, JCP&L filed its 2002 RAC case for review of all actual and projected costs and expenditures, including related insurance recoveries, incurred and to be incurred by JCP&L relating to the environmental remediation of its former manufactured gas plant sites for the period from January 1, 1996 through July 31, 2003. The Company filed its CED case on July 17, 2002, concerning the prudency and recoverability in rates of its Consumer Education Program costs related to restructuring, through July 31, 2002. On August 1, 2002, JCP&L filed its base rate and deferred balances cases. JCP&L filed a motion to consolidate these four filings due to their interrelationship. The parties did not object to the granting of this motion.

The four petitions [redacted]

On August 22, 2002, the Board transmitted JCP&L's four petitions to the OAL for hearings. On October 21, 2002, ALJ Irene Jones was assigned to preside over the four cases. By letter dated October 24, 2002, the BPU requested that the ALJ submit her Initial Decision by May 1, 2003, to enable the Board to render its decision by August 1, 2003.

ALJ Jones conducted a prehearing conference on October 31, 2002, in which counsel for the Company, and the statutory parties to the case, the RPA and Staff participated. Counsel for Co-Steel Sayreville, Inc. ("Co-Steel"), Green Mountain Energy Co. ("GMEC") and the IEPNJ also participated in the prehearing conference. A Prehearing Order on the base rate and deferred balance cases was issued on December 4, 2002, setting forth, among other things, the issues to be litigated and the schedule going forward. A Prehearing Order dated December 5, 2002, set forth the issues to be litigated and the schedule for the RAC case.

Throughout the course of the proceedings, various parties filed Motions to Intervene and/or Participate. The ALJ granted Motions to Intervene by Co-Steel, the New Jersey Commercial Users ("NJCU"), IEPNJ, New Jersey Transit Corporation ("NJT") and the United States Department of Defense and other Federal Executive Agencies ("DOD/FEA"). The ALJ granted participant status to Public Service Electric and Gas Company ("PSE&G"), Rockland Electric Company ("RECO"), PPL EnergyPlus ("PPL"), and GMEC.

Consolidated public hearings were held in Ocean and Monmouth Counties on December 10, 2002 and in Morris County on January 6, 2003. Further public hearings were held in Monmouth and Ocean Counties on March 13, 2003, and in Morris County on March 21, 2003.

ALJ Jones presided over evidentiary hearings in Newark on January 15, February 20, 21, 25-27, March 3-7, and 17-19, 2003. On March 18, 2003, the Board transmitted to the parties the Phase I Audit Report prepared by M&T and BWG. (Exhibits S-37 and S-38). Thereafter, a final evidentiary hearing was held on April 28, 2003.

On March 25, 2003, the BPU sent a letter to the ALJs hearing the various deferred balances cases notifying them of the BPU's decision to recall certain issues from these cases. For JCP&L, the Board indicated that the prudency of the Freehold buyout would be addressed in a pending BPU proceeding in Docket No. ER95120633. The Board also recalled issues related to the securitization/amortization of each utility's deferred balances. Specifically, the BPU recalled the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized (and the appropriate length of the amortization and the interest rate). The Board also recalled the issue of how much of the prudently incurred deferred balances is legally eligible for securitization under EDECA. The Board directed the ALJs to make findings as to the level of prudently incurred deferred balances for each utility, and indicated that the BPU would establish a transitional amortization mechanism rate for such deferred balances between August 1, 2003, until such time as it decided the issue of securitization/amoritization and any authorized transition bonds were issued. The Board indicated that to the extent that the parties had made proposals for transitional deferral recovery in their cases, those portions of the record would be reviewed and decided by the Board as part of its final decisions in these cases.

The parties filed initial and reply briefs on May 7, 2003 and May 21, 2003, respectively, which addressed the issues of cost of capital, revenue requirement, depreciation, service reliability, cost of service/rate design, BGS and other MTC deferred balance issues, DSM, CED, RAC, other SBC deferred balances, and transitional deferral recovery.

On June 16, 2003, the parties to the RAC case, JCP&L, Staff and the RPA, filed with the ALJ a proposed Stipulation of Settlement ("RAC Settlement") resolving all contested issues in the RAC proceeding.

By letter dated June 27, 2003, JCP&L filed with the ALJ a non-unanimous proposed Stipulation of Settlement of the base rate, deferred balances and CED cases ("Joint Position"). The signatories to the Joint Position included JCP&L, Co-Steel, NJ Transit, DOD/FEA, NJCU, and IEPNJ. Significantly, Staff and the RPA were not signatories to the Joint Position, nor did they participate in settlement negotiations.

On July 2, 2003, ALJ Jones issued an Initial Decision in the RAC case recommending approval of the RAC Settlement ("RAC ID") and a second Initial Decision in the base rate, deferred balances and CED cases recommending approval of the Joint Position ("Joint Position ID").

No Exceptions were filed to the RAC ID. Exceptions were filed, however, to the Joint Position ID. On July 14, 2003, Exceptions were received from the RPA, and Staff, and comments in support of the Joint Position were received from JCP&L. By letter dated July 15, 2003, Co-Steel advised that it would not file Exceptions, but reserved its right to file a Reply to Exceptions. On July 21, 2003, Replies to Exceptions were received from the RPA, JCP&L, Co-Steel, and DOD/FEA. On July 22, 2003, NJCU filed a Statement in Support of Initial Decision. On July 23, 2003, the RPA filed a response to the Reply to Exceptions filed by JCP&L.

On August 1, 2003, the Board issued a Summary Order in the consolidated proceedings. The Board adopted the ALJ's RAC ID. However, the Board rejected the ALJ's Joint Position ID. The Board made summary findings on the various issues in base rate, deferred balances and CED cases based on its review of the record and indicated that a Final Order containing a fuller discussion of the issues and the Board's reasoning would follow.

On August 18, 2003, JCP&L filed with the Board a Motion for Rehearing, Reconsideration, and Partial Remand of the Board's August 1, 2003 Summary Order. Answers to JCP&L's Motion were filed on August 29, 2003, by the RPA and Staff. A letter Reply to Answers was filed by JCP&L on September 5, 2003. On September 8, 2003, the RPA filed a letter Motion asking the Board to disregard JCP&L's September 5, 2003 Reply to Answers or, alternatively, to establish a procedural schedule for the RPA to respond to JCP&L's assertedly improper filing of a Reply to Answers. By letter dated September 11, 2003, JCP&L responded to the RPA's September 8, 2003 Motion. On September 18, 2003, the RPA filed a letter in response to JCP&L's September 11, 2003 letter.

At its October 10, 2003 agenda meeting, as memorialized by a letter from its Secretary, dated October 20, 2003, the Board determined to hold JCP&L's motion in abeyance,

pending the issuance of a Final Order. The Board indicated that JCP&L could renew or supplement its motion after the Final Order is issued.

II. RAC CASE

On July 2, 2003, ALJ Jones filed her Initial Decision approving the RAC Settlement executed by JCP&L, the RPA, and Staff. The RAC Settlement provided that:

(1) JCP&L will credit (write-off) $2,500,000 to the deferred RAC balance within 45 days after issuance of a final Board Order approving the RAC Settlement.

(2) The adjusted ending deferred RAC un-recovered balance, as of December 31, 2002, including certain accounting adjustments recorded after December 31, 2002, totals $678,396. The parties agree that this adjusted un-recovered balance was reasonably incurred and should be approved for recovery through the Company's Tariff Rider RAC, together with any other amounts determined to be recoverable through Rider RAC in a subsequent proceeding. This amount shall be reflected in the RAC factor effective June 1, 2004, subject to the $2,500,000 write-off.

Interest on JCP&L's over or under-recovered deferred RAC balance shall be calculated on a monthly basis upon the average of the beginning and ending monthly balances of deferred RAC costs, less accumulated deferred income taxes associated therewith, at a rate equal to the rate on seven-year constant maturity Treasuries as shown in the Federal Reserve Statistical release on or closest to August 1 of each year, plus 60 basis points. Interest shall be compounded annually on August 1 of each year, commencing August 1, 2004, by adding the accrued interest from the prior 12-month period to the principal balance on which interest is calculated. The interest shall be calculated on a prospective basis only, beginning 45 days after the issuance of a Final Order approving the RAC Settlement.

(3) Beginning in December 2003, JCP&L agrees to file for annual RAC rate reviews by the end of December of each year. Each such annual RAC filing will include actual data through November 30 and forecasted data for December of that year, including a true-up adjustment for the prior RAC period for forecasted recoveries from the prior RAC period. The forecasted December data of each year shall be updated to actual during the course of the annual review proceeding. The RAC balance as of December 31, 2002, shall be included in the amount that is approved for inclusion in the RAC factor on June 1, 2004, without further review of the expenses that are reflected in that balance.

(4) JCP&L's manufactured gas plant ("MGP") remediation expenditures incurred on and after January 1, 2003, shall remain subject to review by the RPA and Staff to determine their reasonableness and prudence. The parties agree that no party shall seek to apply any part of the internal non-MGP environmental cost allowances allowed in JCP&L's last base rate case as an offset to recovery of any otherwise reasonable MGP expenditures for the period from January 1, 2003 through July 31, 2003.

(5) The RAC Stipulation resolves all issues relating to the calculation of the JCP&L deferred RAC account through December 31, 2002.

No party filed exceptions to the RAC ID. At its July 25, 2003, agenda meeting, as memorialized in its Summary Order of August 1, 2003, the Board determined based on

its review of the record in the RAC proceeding, as well as the RAC ID that the RAC Settlement was a just, reasonable and fair resolution of this matter and, accordingly, adopted the RAC Settlement and the RAC ID as a full and final resolution of the RAC case. In this Final Order, the Board **HEREBY REAFFIRMS** its findings in this matter embodied in the August 1, 2003 Summary Order.

III. BASE RATE, DEFERRED BALANCES, and CED CASES

A. Litigated Positions of The Parties

As noted above, on August 1, 2002, JCP&L filed its base rate and deferred balances petitions. In total, the Company's filings sought approval for an overall combined increase in rates of $153 million, or 7.8%, assuming approval of the securitization of its projected deferred balances over a term of 15 years. In the event that the Company did not receive authorization to securitize its projected deferred balances over 15 years, the Company's combined request would amount to an increase of $279 million, or 14.3%, assuming a 4-year amortization.[2]

Subsequent to its August 1, 2002 filings, JCP&L submitted amendments to its filings in the form of updates, based upon 12 months of actual data for the test year ended December 31, 2002. The updated filings proposed a combined overall increase in rates of $122 million, or 6.1%, assuming securitization of the Company's deferred balance. If securitization is not approved, the updated data proposed a combined overall increase in rates of $246 million, or 12.4%, assuming a 4-year amoritization.

JCP&L's filings were scrutinized during eleven days of hearings.[3] The RPA filed extensive testimony and briefs challenging many aspects of the Company's request. Staff raised numerous concerns in cross-examination and filed extensive briefs setting forth its recommendations with respect to cost of capital, revenue requirements, depreciation, service reliability, cost of service/rate design, deferred balances issues, and transitional deferral recovery. Other parties filed more limited testimony and briefs, generally limited to their particular narrow areas of concern, primarily as to the impact of JCP&L's filings on their particular tariffs. Extensive initial and reply briefs were filed by JCP&L.

A detailed discussion of the litigated positions of JCP&L, Staff and the RPA on the various issues is contained in the Discussion and Findings Section, infra.

B. Joint Position

By letter dated June 27, 2003, JCP&L filed with the ALJ a non-unanimous proposed Stipulation of Settlement of the base rate, deferred balances and CED cases ("Joint Position"). The signatories to the Joint Position were JCP&L, Co-Steel, NJ Transit, DOD/FEA, NJCU, and IEPNJ. Significantly, neither Staff nor the RPA signed the Joint

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[2] See Footnote 1.

[3] Because of the technically complex nature of ratemaking proceedings, direct testimony is prefiled such that the hearings consist largely of cross-examination.

Position nor participated in the negotiations leading to the proposed settlement. A brief summary of the Joint Position follows.

1. Base Rate Issues

The Joint Position provides for an increase in revenues of $31 million on an annual basis effective for service rendered on and after August 1, 2003. This amount reflects a decrease in delivery revenues of $80 million on an annual basis and the elimination of the existing 5% bill credit and other adjustments to the Company's filed position. The Joint Position provides the Company with a total rate base of $2,017 million, with a 9.14% overall weighted average rate of return, and a 10.6% return on common equity. The capital structure utilized for purposes of setting the rate of return is 41.05% debt, 54% common equity, and 4.95% preferred stock. (Joint Position, ¶1,2,3).

The Joint Position provides for no change in the depreciation rates or methodology for annual up-dates for JCP&L's electric transmission, distribution, and general plant for financial reporting and ratemaking purposes. (Id. ¶4).

The Joint Position provides for a levelized revenue requirement of $8.8 million for the recovery of the accumulated restructuring transition costs, totaling $70.5 million over eight years. This includes the elimination of $0.7 million due to deferral of the New Jersey Clean Energy Program lost revenues. (Id. ¶5,6)

The Joint Position proposes that all issues, proposed indices and other metrics relating to measures of service reliability and performance should be considered in ongoing or future generic investigations or rulemaking proceedings, rather than in the instant proceeding. (Id. ¶7).

2. Deferred Balances Issues

The Joint Position reduces JCP&L's annual SBC revenues by $16.8 million effective for service rendered on and after August 1, 2003. The Joint Position expressly adopts the RAC Settlement with respect to the RAC component of the SBC. It also provides that to the extent the Board orders interim or permanent Universal Service Fund ("USF") or Lifeline Program costs, JCP&L will defer these and receive full and timely recovery thereof through its SBC for the full costs associated with these programs. The Joint Position specifies that the Nuclear Decommission Costs ("NDC") component of the SBC include recoveries associated with the Oyster Creek, TMI-1, Saxton, and TMI-2 nuclear power plants and that interest accrued during and after the Transition Period on these deferred balances will continue to be calculated on a net-of-tax basis. (Id. ¶8).

The Joint Position asserts that the MTC/BGS deferred balance through July 31, 2003, has been reasonably and prudently incurred, and would allow JCP&L to recover the entire amount on an interim basis over ten years. The Joint Position provides for an MTC factor of 11.935 Mils/kWh effective August 1, 2003. (Id. ¶9, 10a, Schedule SJG-6, Attachment 3).

The Joint Position provides that interest accrued on or after August 1, 2003, will be computed monthly on the net-of-tax deferred balances for all components of the MTC and SBC, and compounded annually. For deferred balances other than the RAC and the MTC/BGS deferred balance, the interest rate on or after August 1, 2003, will be based

on two-year constant maturity Treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year, plus 60 basis points. The rate applicable to the MTC/BGS deferred balance would vary depending on when and/or if the Board approves securitization of this balance. (Id. ¶10a, 11).

The Joint Position provides that from May 1, 2001 until the Board approves the protocols for measuring energy savings under the New Jersey Clean Energy Program, JCP&L will defer lost revenues based on the due energy savings as reported in the quarterly New Jersey Clean Energy Program Reports filed with the Board. JCP&L would receive full and timely recovery of the revenue deferrals through its SBC. Once approved by the Board, the protocols would be used to calculate lost revenues on a prospective basis. (Id. ¶12).

The Joint Position provides that JCP&L will continue to sell NUG power and the output of any generation assets that continue to be owned by JCP&L into the PJM Spot Market unless and until the Board determines that a different selling protocol is appropriate. (Id. ¶14).

3. CED Issues

The Joint Position provides that the total CED costs through July 31, 2002 are reasonable. (Id. ¶13).

4. General Tariff, Cost of Service and Rate Design Issues

The Joint Position provides that JCP&L's proposals with respect to (1) modifications of some of the terms and conditions in its Tariff for Service; (2) the elimination of Service Classification OTR and certain Riders, and (3) certain proposed fee changes (e.g., Reconnection Charge, Service Charge for final bill readings outside of normal working hours and Field Collection Charge) that JCP&L requested in its filing are reasonable and should be implemented. (Id. ¶15).

The cost of service methodology for use in the Company's future rate cases was not agreed upon. Accordingly, the Joint Position provides that any party may submit, as part of an appropriate future proceeding, an alternative cost of service methodology. A party to such proceeding is not obligated to rebut the methodology offered by another party to establish the justness and reasonableness of any particular methodology. (Id. ¶12).

The Joint Position modifies JCP&L's Commuter Rail Service Special Provision in the Tariff for Service Classification GT to provide that the week-day hours of 5:00 p.m. to 8:00 p.m. shall be considered off-peak for billing purposes for NJT. In addition, where traction power is supplied at high voltage (230kV) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand. (Id. ¶18).

The Joint Position provides that, as of August, 1, 2003, JCP&L's Special Provision for DOD/FEA in the Tariff for Service Classification GT will provide a credit against distribution kW and kWh charges and will be calculated so as to provide an overall reduction in charges to DOD/FEA customers. The aggregate reduction will be $3.367 million on an annual basis, based on 2002 usage, as compared with rates in effect on

January 1, 2003, after taking into account the effects of the lower charges for Service Classification G and the credit. (Id. ¶21).

The Joint Position further provides that upon the expiration of Co-Steel's existing contract for service on April 1, 2004, Co-Steel will be served as a Service Classification GT customer. Co-Steel will be subject to all provisions and charges provided for in Service Classification GT except that: (1) the Distribution Charge for Co-Steel will be $1.87 per kW based only on the actual maximum monthly 60-minute demand for the current billing period, whether on-peak or off-peak; (2) the distribution KVAR charges will not be applied to Co-Steel, and (3) an MTC credit of $0.009844 per kWh will be applied to all kWh usage for Co-Steel. (Id., ¶22).

The Joint Position provides that the rate design for the demand (kW) charge component of the delivery charge will be modified to eliminate intra-class customer impact disparities between commercial and industrial customers. Service Classification GST customers will have an increase in the tariffed monthly Customer Charge of $11.54 and $16.47 for single-phase and three-phase, respectively. All other tariffed monthly Customer Charges will remain unchanged. (Id., ¶23).

The parties to the Joint Position agree that the underlying principle of ratemaking should be the gradual elimination over time of interclass subsidies so that the "unitized rate of return" for all classes will be 1.0. JCP&L agrees to adopt and support this gradual approach to "unity" in future proceedings. (Id., ¶24).

C. Initial Decision on Joint Position

On July 2, 2003, ALJ Jones issued a short Initial Decision recommending adoption of the Joint Position as filed. The ALJ found that the parties to the Joint Position had voluntarily agreed to its terms and summarily concluded that the Joint Position represented a fair and reasonable resolution of all issues in these cases. The ALJ did not make any specific findings

The Company asserts that the major impacts on its rates stems from two aspects of EDECA that the Company argues are beyond its control. First, JCP&L contends that the annual interim recovery of $67 million of its deferred balance reflected in the Joint Position is a result of the inadequacy of JCP&L's previously capped rates under EDECA to recover the full market costs of supplying BGS to its retail customers. Second, effective August 1, 2003, the new auction-based BGS rates that were previously approved by the Board will be substituted for the existing shopping credits which were set in the Restructuring Orders. These new auction based BGS rates will result in an average bill increase for fixed-price BGS customers of about 7.5%. (Id. at 4-5).

2. *RPA*

The RPA filed Exceptions comprised of two volumes spanning nearly 100 pages. The RPA asserts that: (1) neither the Staff nor the RPA participated in the settlement discussions nor were signatories to the Joint Position; (2) because only representatives of the Company's large energy users participated in the settlement discussions, and because these parties did not participate in the all aspects of the case, the Joint Position fails to represent the interests of the Company's residential and small business customers, who comprise the overwhelming majority of the Company's customers; and (3) the Joint Position lacks compromise because the signatories all received advantageous results very close to their litigated positions at the expense of residential and small business customers. (RPA Exceptions at 1).

As more fully discussed below, the RPA also took specific exception to a wide range of issues within the Joint Position. The RPA requests that the Board reject the ALJ's Initial Decision approving the Joint Position and adopt the positions advanced by the RPA at hearing.

a). Cost of Capital

The RPA urges the Board to reject the 9.14% overall rate of return in the Joint Position and instead, approve an overall rate of return of 808%. The RPA argues that its proposed 8.08% return is based on the only actual capital structure contained in the record. (RPA Exceptions, Vol. 1 at 6, 8 and 9). Unlike the Company's proposed stand-alone capital structure, the RPA asserts that its proposed consolidated capital structure guards against manipulation, is consistent with the practices of credit reporting agencies who do not solely rely on stand-alone capital structures in their evaluations, and properly passes savings from lower financing costs to JCP&L's ratepayers. (Id. at 9-10).

The RPA recommends that, as a component of the overall rate of return, the Board approve a 9.85% return on common equity, including an adjustment of 35 basis points in recognition of FirstEnergy's highly leveraged capital structure. (Id., at 13-25).

b). Revenue Requirement

Rate Base: The RPA takes issue with the Joint Position's rate base of $2.017 billion. The RPA faults the Joint Position and the ALJ for failing to consider certain adjustments proposed by the RPA. Specifically, the RPA cites to modifications it proposed on the record to adjust certain components of the Company's Cash Working Capital and to

reflect the benefit to the Company from the filing of a consolidated tax return. The RPA recommends that the Board adopt the RPA's proposed rate base of $1.914 billion. (Id. at 26-27).

Pro Forma Operating Income: The RPA proposes several adjustments to various components that comprise the Company's Pro Forma Operating Income, as follows:

Revenue Adjustments: The RPA recommends an increase of $4.684 million to the Company's test year revenues to account for an increase in the Company's residential and commercial customers. (Id. at 32-33).

Expense Adjustments: The RPA faults the Joint Position for not specifying the nature and level of the adjustments made to the Company's litigated positions regarding its expenses. The RPA requests that the Board adopt the adjustments made at hearing by the RPA to the following expenses: (Id. at 33).

Advertising: A disallowance of $958,000 in test-year expenses claimed by the Company for community affairs, public relations, and image advertising was recommended by the RPA.. (Ibid.)

BPU/RPA Assessment: Reduction of the Company's revenue requirement by $13,000 to reflect the reduction in the Company's rates following the completion of the rate case. (Id. at 34).

Charitable Contributions: Disallowance of $752,000 in charitable contribution expenses claimed by the Company. (Id. at 34).

Depreciation: Rejection of the Company's proposed annual net salvage expense of $43.1 million. (Id. at 44-51).

Management Audit: Reduction of JCP&L's management audit amortization allowance by $148,000. (Id. at 35).

Merger Costs: Rejection of $42.696 million in merger costs claimed by the Company. (Id. at 35-36).

SAP Project Evolution Amortization: Reduction of the Company's revenue requirement by $1.697 million for the costs associated with Project Evolution. (Id. at 36-37).

Rate Case/Regulatory Expenses: Modification of the Company's revenue requirement to reflect a 50/50 sharing of actual rate case expenses, amortized over a five-year period. (Id. at 37-38).

Regulatory Asset Amortization: Rejection of the Company's proposal to shorten the recovery period for certain production related assets with a corresponding reduction of $2.604 million to the Company's Operation and Maintenance ("O&M") expense. (Id. at 38).

Restructuring Transition Costs: Disallowance of a requested eight-year amortization of $70.5 million in certain restructuring related costs incurred in 1996, resulting in a net $8.8 million reduction to the Company's revenue requirement. (Id. at 38-39).

Incentive Compensation: Disallowance of $4.818 million for incentive compensation for JCP&L's employees. (Id. at 40).

Miscellaneous Expenses: Reduction of $186,000 to the Company's claimed test-year miscellaneous expense. (Id. at 40-41).

Interest Synchronization: Adoption of the RPA's proposed interest synchronization adjustment. (Id. at 41).

c). Depreciation

The RPA contends that JCP&L's ratemaking treatment for its estimated future net salvage results in an unreasonably large discrepancy between the proposed test-year depreciation expense that the Company seeks to recover for negative net salvage, and the actual amount expended for net salvage. (Id. at 44). The RPA argues that this mismatch stems from the Company's use of future inflation in estimating its net salvage expense which "relates cost of removal in current dollars to retirements in very old historical dollars, thus resulting in very high cost of removal estimates." (Id. at 45). The RPA recommends that the Board approve its net salvage allowance approach whereby an annual net salvage expense is calculated by averaging the past five years of actual net negative salvage expense, which is then added to the annual depreciation expense and included in the Company's revenue requirement.

The RPA also requests that the Board adopt a methodology whereby the cost for removing a retired asset be charged to the cost of its replacement. (Id. at 51). The RPA further urges that JCP&L be required to submit a detailed annual report to the Board and RPA showing all aspects of its annual deprecation rate update calculations. (Id. at 51-52).

d). Service Reliability

The Joint Position provides that the concerns over JCP&L's service reliability will be addressed in ongoing or future generic investigations and rulemaking proceedings. The RPA rejects this position and recommends that the Board act to address service reliability concerns by adopting the Service Quality Index and individual customer rebates as proposed by the RPA.

e). Rate Design

The RPA takes Exception to the Joint Position's modifications to JCP&L's current rate design.

1. Reconnection and Service Charges: The RPA asserts that increases to the current reconnection and service charges may unreasonably burden those ratepayers needing such services and that their derivation was not consistent with past Board practices. Thus, the RPA recommends that the Board reject the proposed increases and maintain the current levels of charges for these services. (Id. at 59-60).

2. Market Transition Charge: The RPA opposes the Company's proposal to recover MTC revenues through a methodology that the Board has historically applied to LEAC

under-recoveries. The RPA argues for maintenance of the current methodology used to recover MTC revenues because it (1) properly balances MTC responsibility among the Company's rate classes; (2) avoids any adverse impact to Company's Residential Service and General Service customers; (3) affords all rate classes an opportunity to benefit from competition, and (4) avoids substantial increases to some of the Company's rate classes. (Id. at 61-63).

3. Customer-Specific Rate Design Changes: The Joint Position provides for several modifications to the proposed rate design filed by the Company which are specific to the needs of those customers who were signatories thereto.

? Co-Steel: The RPA objects to allowing Co-Steel to bypass the MTC charge through the characterization in the Joint Position of the non-bypassable MTC charge as a credit. The RPA notes that EDECA imposes collection of the MTC from all electric public utility customers. Because Co-Steel is a customer of JCP&L, the RPA argues that there is no basis to allow Co-Steel to avoid its legal obligation to pay the MTC charge. (Id. at 63-65).

? NJT, DOD/FEA, NJCU: The RPA considers the Joint Position's provisions for NJT, DOD/FEA and NJCU's special treatment [illegible]

g). Clean Energy Program

The RPA opposes the provision within the Joint Position that allows the Company full recovery of "lost revenues" associated with the Board-approved Clean Energy Program ("CEP"). The RPA argues that although the Joint Position states that the proposed revenue requirement eliminates recovery of these lost revenues, the nature of the Joint Position makes it impossible to determine whether, in fact, the proposed rates include such a recovery. (Id. at 21-22). The RPA further opposes granting the Company guaranteed revenues of all lost revenues in the amounts claimed by the Company from May 1, 2002 through the effective date of a Board Order approving the protocols for determining energy savings. The proceedings seeking Board approval of the energy savings protocols are currently pending. The RPA argues that this provision is in direct

E. REPLIES TO EXCEPTIONS

1. JCP&L

a). Cost of Capital

The Company asserts that the Joint Position's capital structure, associated capital costs, return on equity of 10.6% and overall rate of return of 9.14% are well within the zone of reasonableness as supported by the record testimony of its three expert witnesses who testified on the issue, and that the Joint Position represents a reasonable compromise that should be adopted by the Board. (JCP&L Reply Brief on Exceptions at 7-9).

b). Revenue Requirement

Rate Base: The Joint Position provides for a rate base of $2,017 million, which the Company notes is $37 million less than the amount it supported in its 12+0 Update, and is virtually the same rate base amount ($2,016.3 million) recommended by Staff. (Id. at 10). JCP&L argues that the rate base proposed in the Joint Position fully recognizes Staff's position regarding consolidated income tax savings. JCP&L further asserts that the RPA's Cash Working Capital arguments have been repeatedly rejected by the Board in numerous prior cases. (Id. at 10-11).

Operating Income: Responding to the RPA's criticism that the Joint Position does not provide an explicit breakout of individual issues relating to JCP&L's pro forma revenues and expenses, the Company asserts that the Joint Position represents an overall compromise of all income and expense issues. (Id. at 11). JCP&L asserts that the lack of specificity of individual items in dispute is the same approach used in the settlement of the PSE&G rate proceeding that was recently approved by the Board without any objection by the RPA. (Ibid.). JCP&L further argues that the RPA overlooks the $80 million decrease in its delivery rates provided for in the Joint Position and asserts that this amount is nearly twice the $41.6 million decrease supported by the Company's 12+0 Update. (Ibid.).

c) Depreciation

JCP&L contends that, as proposed in the Joint Position, there should be no change in its existing depreciation rates and methodologies. These rates were reviewed and approved by the Board only after submission by the Company of a full-fledged depreciation study. There is no such study in the record of this matter before the Board. In the absence of a similar depreciation study, JCP&L maintains that an action by the Board accepting the type of modification as proposed by the RPA would be inappropriate. (Id. at 12). JCP&L further urges rejection of the RPA's proposal regarding the treatment of the future costs for removal of utility plant. JCP&L argues that the Board, FERC and the National Association of Regulatory Utility Commissioners have historically recognized inclusion of such costs as a proper element in current depreciation rates, and that this issue should only be decided in a proceeding where such removal costs are fully studied and analyzed on the basis of current forecasts and projections. (Id. at 12-13).

d). Service Reliability

In response to the RPA, JCP&L argues that: (1) Staff supports the Company's position on reliability issues, recommending that the RPA's issues should continue to be addressed in other reliability-related proceedings currently or prospectively before the Board; (2) the RPA is improperly attempting to use these proceedings to justify the imposition of a regulatory mechanism that would set service standards, a performance tracking mechanism, and penalties for failure to meet the standards because a base rate proceeding is not the appropriate vehicle in which to consider these issues, especially in light of the ongoing generic investigative and rulemaking proceedings that the Board has or will initiate under EDECA; (3) the RPA incorrectly asserts that the Company's testimony regarding capital investments made to further its reliability efforts, introduced the issue of reliability into this proceeding and that, by arguing that reliability should not be an issue in this proceeding, the Company sought to evade review of these capital investments; (4) the RPA neither challenged nor investigated any of JCP&L's reliability-related capital investments, and (5) the RPA's attempt to introduce into the Board's decision-making process hearsay newspaper accounts of recent outage events and materials that were not previously made part of the record to the proceeding raises due process concerns. (Id. at 13-17).

e). Rate Design

Special Charges: The Company disputes as unsupported the claims made by the RPA that increasing the Reconnection and Service charges will disproportionately burden the Company's needy customers. The Company reasons that, under cost of service principles, costs incurred by a utility for service should be the responsibility of the customer or customers who cause such costs, and that in cases where a customer is suffering financial hardship, the Universal Service Fund is the appropriate source of assistance. (Id. at 18-19).

Market Transition Charge: JCP&L contends that in accordance with EDECA, the Joint Position provides for the calculation of the MTC on a uniform, per kWh basis for all customers in all rate classes, subject only to regular voltage level adjustments and the special Co-Steel credit. Any other approach, the Company argues would denote favoritism or be discriminatory. (Id. at 19-20).

F). Basic Generation Service Prudence Review

JCP&L argues that the RPA's Exceptions repeat the same arguments raised in its briefs, which were responded to in the Company's reply briefs. Nonetheless, JCP&L reiterates its response to some of the key points raised by the RPA. (Id. at 21-25).

Pennsylvania vs. New Jersey Supply Costs: JCP&L rejects the RPA's arguments that because of the absence of a deferral recovery mechanism in Pennsylvania, JCP&L's Pennsylvania affiliates had a stronger incentive to control provider of last resort costs, as BGS costs were referred to in Pennsylvania. The Company argues that (1) it always knew that it would need to justify its costs in the context of a prudence review; (2) the unrefuted testimony of its witness at hearing demonstrates that both JCP&L and its Pennsylvania affiliates implemented the same power procurement methodologies, policies, and procedures; and (3) the record contains extensive evidence explaining the

basis for the differences in average prices between New Jersey and Pennsylvania. (Id. at 25-26).

The Company's Procurement Models: JCP&L rejects the RPA's criticism of the Company's procurement models. JCP&L asserts that the RPA mischaracterized the various Company models and that the RPA's arguments on this issue are without merit and display a lack of understanding of real markets. JCP&L asserts that deviations by the Company from the models were affirmed by the Auditors as reasonable and prudent, and that the models were designed to reduce the Company's and its customers' level of risk exposure. (Id. at 27-30).

Weather Hedging: JCP&L asserts that the RPA's criticism of JCP&L for not purchasing weather hedges ignores the Company's reasons for not using weather hedges, namely that weather hedges are thinly traded, are of limited use, and are very costly. (Id. at 36).

Provision of Data: The Company argues that the RPA's complaints about a lack of data are unfounded and that no inference, adverse of otherwise, can be drawn from the Company's action, particularly in light of the substantial amount of data provided by the Company to the RPA. (Id. at 30-31).

Auditor Independence: JCP&L urges the Board to reject the suggestion by the RPA that the Auditors did not conduct an independent review and analysis of the Company's statements. The Company asserts that while the Auditors did on several occasions adopt language verbatim from materials supplied by the Company, the record shows that this was done only after the Auditors had independently verified their conclusions, and there was no reason why such language should not be used, particularly if the point had already been properly articulated by the Company. (Id. at 31-32).

g). Miscellaneous

JCP&L asserts that (1) the Freehold Buyout balance is not included in the deferred balance interest calculation; (2) the inclusion of a return of and on the investment in JCP&L's retained generation assets is consistent with the Final Restructuring Order which allows the Company to recover all of its costs associated with its owned generation assets, and (3) the RPA's proposed disallowance of $59.9 million of NUG-related interest costs raised for the first time in briefs is unsupported by the record, contrary to the conclusions of the Auditors, and unsupported by Staff. (Id. at 32).

h). Response to Staff's Exceptions

In response to Staff's Exceptions reiterating Staff's reliance upon its filed positions, JCP&L reiterated its reliance upon its filed positions, particularly with respect to Staff's attempt to bolster its position with extra-record evidence and to compare JCP&L's procurement activities to the prices obtainable on the PJM spot market, which prices the Company asserts would have been different had JCP&L and its affiliates purchased all of their requirements on the spot market. The Company alleges that such an approach would have mirrored the approach that led to the California energy crisis of 2000-2001. (Id. at 32).

i). Clean Energy Program

JCP&L urges the Board to reject the RPA's position opposing JCP&L's recovery of lost revenues associated with implementing the Clean Energy Programs. JCP&L argues that the same type of recovery of lost revenues was recently approved by the Board as part of settlement in PSE&G's base rate filing. The Company further notes that the RPA filed no objection to such recovery in the PSE&G base rate proceeding. (Id. at 33-34).

j). Consumer Education

The Company asserts that the Joint Position provides a resolution of JCP&L's CED case that is substantially similar to the resolution of the issue of CED costs in the settlement of PSE&G's base rate proceeding, which was not objected to by the RPA. JCP&L argues that there is no justification for it to receive treatment that is different than that accorded PSE&G on a similar issue. (Id. at 34-35).

k). Transitional Deferred Balances Recovery

Although the Company proposed an interim recovery mechanism for the MTC/BGS deferred balance different from that proposed by the RPA, it accepts the RPA's proposed interim recovery mechanism provided that it is not implemented on a permanent basis. As a result of a letter from the Board's Secretary dated March 25, 2003, the determination of the appropriate permanent recovery mechanism will be deferred. JCP&L reserves its right to address that issue in the appropriate forum. (Id. at 35-36).

2. DOD/FEA

The Department of Defense and other Federal Executive Agencies did not file Exceptions, but did file a Letter Reply to Exceptions. DOD/FEA urges the Board to adopt the Joint Position, and leave unmodified those Cost of Service/Rate Design provisions within the Joint Position as they apply to DOD/FEA. The DOD/FEA compares the rates its facilities pay for energy in New Jersey with the rates paid in Georgia and finds that the rates in New Jersey are nearly double those in Georgia. (DOD/FEA Letter Reply at 3). DOD/FEA argues that, in part, its greater energy costs in New Jersey are driven by a massive disparity in the rate of return paid by customers, like itself, who take service under JCP&L's General Service Transmission Rate Schedule ("GT"). (Id. at 4). The DOD/FEA asserts that in 2002, GT service customers paid an actual class rate of return of 39.78%. (Id.). The DOD/FEA contends that the present GT rate structure is inequitable and constitutes subsidization by the GT class of customers of other classes of the Company's customers. By approving the Cost of Service/Tariff Design proposed in the Joint Position, the Board would help to remedy past inequities and bring about a more efficient rate structure.

3. CO-STEEL

Gerdau Ameristeel, Inc., formerly Co-Steel Sayreville, Inc., filed a Reply to Exceptions in response to the RPA's Exceptions. Co-Steel argues that (1) the objection by the RPA to the MTC treatment accorded Co-Steel in the Joint Position is inappropriate, procedurally improper, and a violation of due process; (2) pursuant to EDECA, the MTC treatment

accorded Co-Steel is permissible; (3) the MTC treatment accorded Co-Steel is necessary for the continued economic vitality of the Co-Steel production facility and maintaining employment of its labor force; and (4) the MTC treatment accorded Co-Steel in the Joint Position is consistent with comparable treatment accorded Co-Steel in PSE&G's base rate proceeding. (Gerdau Ameristeel Reply to Exceptions at 2-9).

4. NJCU

The Coalition of New Jersey Commercial Users filed a Statement in Support of the Joint Position. The NJCU believes that the Joint Position offers an overall compromise among the signatory parties that is fair and reasonable and consistent with Board policies. In particular, NJCU argues that the Joint Position addresses a principal concern of Staff by allowing the parties a future proceeding to submit alternative cost-of-service methodologies for the Board's consideration, recognizes the need to eliminate interclass subsidies and reduces the interclass subsidy to residential ratepayers. (NJCU Statement in Support of Initial Decision at 2-6).

5. RPA

The RPA's Reply to Exceptions focused on the Company's Comments in support of the Joint Position.

a) Standard Of Review

The RPA maintains that the Joint Position is flawed. It argues that unlike Staff and the RPA, none of the signatories to the Joint Position participated in all of the issues to the proceeding and that this lack of full participation in the issues of the case fatally undermines the validity of the Joint Position. (RPA Letter Reply to Exceptions at 2-7).

b) Revenue Requirements

i. Rate Base

The RPA contends that, although the DOD/FEA filed testimony on the issue of rate base, only the Company, Staff, and RPA fully addressed the issue of JCP&L's rate base. The RPA asserts that the Joint Position does not take into consideration the positions of Staff and the RPA. (Id. at 8).

ii) Capital Structure and Cost of Capital

Except for the DOD/FEA, none of the signatories to the Joint Position addressed the capital structure/cost of capital, nor did these parties attend the evidentiary hearings pertaining to these issues. The RPA argues that the Joint Position's proposed 10.6% return on equity is contrary to current Board policy. (Id. at 8-9).

iii) Operating Income

Although the Joint Position proposes to reduce the Company's delivery rates by $80 million, only the RPA offered testimony regarding adjustments to JCP&L's operating income. None of the non-Company signatories attended the evidentiary hearings or conducted cross-examination of the witnesses who presented testimony on the various

operating income issues. The RPA repeats its arguments that there is no indication of how the parties arrived at the $80 million reduction, and that the inclusion of restructuring costs violates EDECA and general ratemaking principles. (Id. at 9).

c. Depreciation Rates

Again here, the RPA notes that only the Company and the RPA actively participated in the litigation of these issues, and the Joint Position reflects the Company's position and ignores those of Staff and the RPA. (Id. at 10).

d. MTC/BGS Deferred Balance Recovery

Prudence Review of MTC/BGS Deferred Balance: The RPA repeats its criticism of the Joint Position's finding that the entire MTC/BGS deferred balance was reasonably and prudently incurred. The RPA argues that this determination is not supported by credible evidence and that, except for the Company, none of the signatories to the Joint Position filed testimony on the issue and that only the Company, Staff, and RPA appeared at the evidentiary hearing to conduct cross-examination of the Company's witnesses and that only these same parties briefed the issue. The RPA further defends its testimony regarding the price difference between FirstEnergy's, New Jersey and Pennsylvania affiliates as providing a basis to disallow the differential cost. The RPA asserts that the Company was unable to satisfactorily explain the difference in performance between the affiliates and that the performance of the Pennsylvania affiliates was offered as a comparative standard against which JCP&L's performance could be measured. (Id at 4-12).

Recovery/Securitization and Related Carrying Costs: The RPA repeats its argument that the Joint Position proposal on this issue lacks record support. (Id. at 13).

e. SBC Components

The RPA rejects the assertion by the Company that the RPA did not challenge the proposals expressed in the Joint Position regarding the collection of SBC components, full recovery of CEP costs, and the guaranteed recovery of all lost revenues. In addition, the RPA reiterates that the proposal to guarantee the Company full recovery of lost revenues is in violation of a prior Board Order that addressed the claim by utilities for lost revenues.[4] (Id. at 14).

f. Cost Of Service/Rate Design

The RPA asserts that, except for the Company, the nearly exclusive focus of all the signatories to the Joint Position was on issues related to cost of service/rate design. The RPA argues that rather than being a compromise, the Joint Position simply reflects

[4] By letter dated July 23, 2003, the RPA responded to JCP&L's Reply to Exceptions on the lost revenue issue. The RPA disputes JCP&L's assertion that the language in the Joint Position is "virtually verbatim" to the language in the recently approved PSE&G case. The language in the Joint Position includes the phrase "and shall receive full and timely recovery thereof through its SBC for the full amount thereof." The RPA notes that this language, with its unequivocal guarantee of recovery is not in the PSE&G Settlement and has not been approved by the Board.

the litigated positions of those parties, whereby each party agreed to minimize its own share of the expenses associated with delivery service to the detriment of the unrepresented parties. (Id. at 14-15).

[redacted]

g. Other Tariff Changes And Tariff Revisions

The RPA criticizes the provision in the Joint Position proposing to increase the Company's cost-based fees. The RPA argues that these increases would disproportionately affect the residential customer which class was not represented in the Joint Position. (Id. at 15).

h. Service Reliability

The RPA rejects the argument by the Company that the issue of the Company's service reliability should be left to a generic proceeding, and contends that the recent outages in the Company's service territory and the re-emergence of the issue of stray voltage requires immediate Board action through the establishment of reliability standards and customer standards with penalties if the established standards are not met.

IV. DISCUSSION AND FINDINGS

A. Introduction

Among state agencies, the Board's decisions are particularly policy-driven. While certain regulatory principles of public utilities remain constant, such as the mandate that public utilities provide safe, adequate and proper service at just and reasonable rates, the role of public utilities in modern life demands policy evolution. Hence, while the Board must enunciate decisions based on the record, the Board's proceedings are properly considered quasi-legislative. E.g., Atlantic City & c., Co. v. Bd. Pub. Utility Commrs., 128 N.J.L. 359 (Supreme Ct. 1942). In keeping with that dichotomy, we issue this order by way of amplification of our Summary Order of August 1, 2003 in these matters.

The record for these consolidated cases is large. There are no less than five separate petitions. Among them is that quintessentially most detailed of utility proceedings, a base rate case. To further complicate this record, the case also includes examination of the aftermath of the single most drastic overhaul of electric utilities in New Jersey regulatory history, the passage of EDECA. To aid us in this process, we lack the benefit of fact-finding and reasoned, objective recommendations of the Administrative Law Judge. Instead, apparently just before the decision was due to be issued, the Company, with various intervenors, presented a document styled as a settlement.[5] Considering this document, the ALJ, following recitation of the procedural history, wrote the following:

> On June 27, the Petitioner, the New Jersey Commercial Users, New Jersey Transit Corporation, Gerdau Ameristeel Sayreville, Inc. (formerly Co-Steel), Independent Energy

Producers of New Jersey and the Department of Defense/other Federal Executive Agencies filed a stipulation of settlement which resolved all issues in the base rate and the deferred balances filings.

The Board Staff and the Ratepayer Advocate were not signatory to the stipulation but have been duly served by electronic mail with a copy of the settlement. In view of the time constraints imposed by the BPU and the August 1, 2003 deadline for the removal of the caps, any objections to this settlement should be submitted to the Board as exceptions.

After a thorough review of the Settlement, I **FIND** that the stipulation of settlement represents a fair and reasonable resolution of all the issues in this matter. I further **FIND**:

1. The parties to the above-mentioned settlements have voluntarily agreed to their terms as evidence by their signatures or the signatures of their representatives.

2. The settlements fully dispose of all issues in controversy and are consistent with the law.

Therefore, I **CONCLUDE** that the agreements meet the requirements of N.J.A.C. 1:1-19.1 and that the settlements should be approved. Accordingly, it is **ORDERED** that the settlement terms are approved, and it is **FURTHER ORDERED** that the proceedings in this matter be concluded.

[Initial Decision at 5-6]

Thus, the Board was presented with a novel situation. In a complex series of cases involving a major electric utility, in the absence of recommended fact-finding from the OAL, the Company with some intervenors, but neither our Staff nor the Ratepayer Advocate, filed a settlement.

The Board has always been guided by the salutary public policy in favor of settlements. Indeed, the Board has been pragmatic in its recognition of settlement as a sound conclusion of litigation. Notably, the Appellate Division approved the Board's adoption of a non-unanimous settlement including most of the active parties. I/M/O the Petition of Public Service Electric and Gas Co., 304 N.J. Super. 247 (App. Div.) certif. den. 152 N.J. 12 (1997). In so affirming the Board's approach, the Court emphasized the essential soundness of a settlement by the parties "in the best position to determine how to resolve a contested matter in a way which is least disadvantageous to everyone." (Id. at 266.) The concept that the "active parties participate[d] in negotiating the settlement," id. at 270, informed the Court's acceptance of a non-unanimous settlement. There, of

course, both Staff and the Ratepayer Advocate were lively participants and signators to the settlement.[6] Despite general support of settlements, courts have never abandoned their obligation to ensure overall fairness of settlements and protection of all parties. E.g., Eichenholtz v. Brennan, 52 F.3d, 478 (3d Cir. 1998).

In contrast, here, the purported settlement was solely the creature of the Company and New Jersey Commercial Users, New Jersey Transit Corporation, Gerdau Ameristeel Sayreville, Inc. (formerly Co-Steel), Independent Energy Producers of New Jersey and the Department of Defense/other Federal Executive Agencies. Although the document's provenance is hazy, certainly neither Staff nor the Ratepayer Advocate participated in such negotiations which gave rise to the agreement nor did they sign. Instead, both filed exceptions thereto.

Analysis of this document must begin with the observation that none of the signator intervenors could be characterized as fully active participants in the entire proceedings. As large energy users, these parties appropriately participated to the degree they deemed necessary to support their parochial interests. Apart from the Company, the interests of which need go unremarked, the breadth of interests which are necessary to settlement were absent. Thus, the happy results for the Company are unsurprising: 100% of recovery of deferred balance, return on equity of 10.6% and generosity with respect to revenue requirements. For the large customers, the result was agreeable tariff design. In other words, the Company essentially reached a settlement with itself.[7] Accordingly, this settlement and the Initial Decision adopting it are **HEREBY REJECTED** except insofar as particular tariff design components are adopted as will be set forth below.

Related to this rejection is NJCU's motion before the OAL for partial summary disposition on the issue of cost of service methodology to avoid conflict between this case and the parallel Public Service Electric and Gas case. While NJCU was a party to the settlement approved by the ALJ in the Initial Decision to conclude the OAL proceedings, our rejection of that decision theoretically revives the motion. The issue is moot because of the resolutions of both proceedings. Further, NJCU both failed to provide factual support in the record in support of the motion and to know that it is entitled to judgment as a matter of law. Brill v. Guardian Life Ins. Co., 142 N.J. 520 (1995). Accordingly, the motion is **HEREBY DENIED**.

As set forth in the Summary Order, we generally adopt the recommendations of Staff which sometimes were congruent to those of the Ratepayer Advocate. Because the positions of the parties were so critical to our analysis of the issues in these proceedings, we have generally set them forth in some detail following our discussion and analysis. The format varies somewhat between the rate case and its traditional issues and the uncharted territory of the deferred balances component. To this extent,

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[6] Of course, New Jersey has never endorsed uncritical acceptance of a utility's records. E.g., Public Service CoordinatedTrans. v. State, 5 N.J. 196, 218 (1950).

[7] To the extent JCP&L would attempt to articulate some sort of fungibility argument generally with respect to New Jersey electric utilities and specifically with respect to settlements, that effort is misguided. As to the former, no comment is necessary. As to the latter, we note that while neither Staff nor the Ratepayer Advocate signed the settlement in the parallel proceeding for Public Service Electric and Gas Co., both Staff and the Ratepayer Advocate actively participated in the negotiations.

we do not do so under every issue and subissue which do not follow precisely this order, we **HEREBY ADOPT** the recommendations of Staff as our findings for the following issues as supplemented where indicated by the recommendations of the Ratepayer Advocate:

Rate Case

- ? Cash Working Capital
- ? Consolidated Taxes (with Ratepayer Advocate)
- ? Customer Growth
- ? Clean Energy - Lost Revenues (with Ratepayer Advocate)
- ? Charitable Contributions (with Ratepayer Advocate)
- ? SAP/Amortization of Expenses (with Ratepayer Advocate)
- ? Rate Case Expenses (with Ratepayer Advocate)
- ? Production-Related Amortization (with Ratepayer Advocate)
- ? Restructuring Transition Costs
- ? Incentive Compensation
- ? Miscellaneous
- ? Interest Synchronization
- ? Gross Receipts and Franchise Tax (with Ratepayer Advocate)
- ? Performance Standards
- ? Rate of Return (Staff as modified herein)
- ? Capital Structure

Deferred Balance Case

- ? With Auditors, Staff and Ratepayer Advocate as modified herein

B. Cost of Capital

JCP&L

JCP&L proposes a rate of return of 12.0% on its common equity capital, provided that its requested rate relief and the securitization of its deferred balances are approved. In reaching its requested rate of return, JCP&L balanced various considerations including (1) fairness to the ratepayer; (2) ability to attract capital on reasonable terms; (3) maintenance of its financial integrity, and (4) comparability of its return to the returns offered on other comparable risk investments. JCP&L used three market-based methodologies to derive its estimated cost of capital: (1) the Capital Asset Pricing Model ("CAPM") Risk Premium (JC-6; P113 at 23-49); (2) the Empirical Risk Premium, and (3) several Discounted Cash Flow ("DCF") methodologies. More specifically, in arriving at a range of estimates reflecting the various applications of the above methodologies, JCP&L performed two CAPM analyses, both a simple CAPM and an empirical approximation of the CAPM; a historical risk premium analysis for the electric utility industry, and the natural gas distribution utility industry, and a study of the risk premiums actually allowed in the electric utility industry; and a DCF analysis on two surrogates for JCP&L's electric distribution business, including a group of comparable natural gas distribution utilities and a group of combination gas and electric utilities. (JC at 14; PIB at 28-39). JCP&L's use of three market-based methodologies is due to the inability of one

individual method to provide the necessary level of precision for determining a fair rate of return. JCP&L asserts that, when viewed in conjunction with each other, each method serves as a check and provides a useful basis on which to make an informed judgment. Based on the results of the various analyses it conducted, JCP&L arrived at a range of 10.8% to 13.2% as the appropriate ROE. (JC-6 at 41; PIB at 24-41).

The range of ROE estimates obtained through application of the various methodologies averaged to about 11.75%, which JCP&L asserts reflects the risk of the average distribution company. JCP&L argues that because its investment risk slightly exceeds those of the group, the expected equity return has a downward bias. JCP&L estimates this bias at 25 basis points, which when applied to its average estimated ROE brings its requested ROE to 12.0%. (JC-6 at 4; PIB at 25-26).

RPA

The RPA recommends a ROE of 9.5% plus an additional 25

regulated higher risk ventures that could distort, i.e., increase, the estimate of the average return on equity of the sample companies. (SIB at 17-18).

Staff asserts that JCP&L's analysis does not capture the significant reduction in the risks it faces as a result of restructuring, divestiture of its generating assets, and the shifting of generation risks to consumers via the auction. Staff asserts that JCP&L's use of non-comparable proxy groups leads to estimates that do not reflect its new risk profile. (SIB at 22-32). Staff reviewed JCP&L's results for the various iterations of the CAPM, Risk Premium and DCF models, and argues that the natural gas and the combination gas and electric industries are not comparable to JCP&L, and that the electric industry estimates include the major risk factor of electric generation which is not present in JCP&L's risk profile. (SIB at 23-28). Staff reasons that JCP&L's customers should pay

C. Capital Structure

JCP&L

Consistent with the Board's October 9, 2001 Order approving the merger of JCP&L's then parent company, GPU Inc., and FirstEnergy, Inc. ("FirstEnergy") ("Merger Order"), JCP&L filed two alternative capital structures; a consolidated capital structure based on FirstEnergy's capital structure and a "stand-alone" JCP&L capital structure. (Exhibit JC-5, Schedule TCN-1). JCP&L supported the use of the stand-alone capital structure, provided that two adjustments were made to its actual capital structure. The first adjustment eliminates the purchase accounting adjustments associated with the capitalization portion of the JCP&L balance sheet. The second adjustment removes the effects of the $300 million deferred balance write-off as required by in the Merger Order. (Id. at 8-9) JCP&L asserts that the capital structure resulting from these adjustments is fair to its customers and to the Company and is vital to maintaining its access to the capital markets.

JCP&L's proposed capital structure includes 57.22% common equity, 4.95% preferred stock and securities and 37.83% short-term debt. (JC-5, Schedule TCN-6).

JCP&L rejects the use of a consolidated capital structure for ratemaking purposes. It argues that using a consolidated capital structure would not produce the savings envisioned by the RPA, because only $2.2 billion of First Energy's new debt was used to finance the $4.8 billion purchase price of the GPU merger and more than half of the purchase price or $2.6 billion was paid in the form of new common equity stock issued by FirstEnergy to GPU stockholders. (JCP&L Initial Brief at 19).[9]

JCP&L asserts that virtually every major public utility in the State is structured as a local operating subsidiary of a larger parent holding company, and that the Board has not substituted the parent holding company's capital structure for that of the operating utility for ratemaking purposes. (PIB at 21). In addition, JCP&L observes that unlike in the instant proceeding, the RPA, which is a party to the PSE&G rate proceeding, did not in that case recommend using a consolidated capital structure.

RPA

The RPA recommends use of FirstEnergy's consolidated capital structure for ratemaking purposes. It opposes the use of a stand-alone capital structure, and rejects the two adjustments proposed by JCP&L. The RPA argues that a stand-alone capital structure deprives the ratepayers of the benefits of the lower capital costs associated with the $4.5 billion in long-term debt issued by FirstEnergy to finance the merger. The RPA asserts that the use of a consolidated capital structure is consistent with the Board's recent telecommunications decision, wherein, the Board adopted the RPA's proposed

[9] Petitioner, JCP&L's Initial Brief will hereinafter be referred to as "PIB". The Ratepayer Advocate's Initial Brief will be referred to as "RAIB" and the Staff's Initial Brief will be referred to as "SIB".

consolidated capital structure[10]. (RAIB at 7). In addition, the RPA asserts that a consolidated capital structure is less susceptible to manipulation, in that FirstEnergy's capital structure resulted from arms-length transactions in the capital markets, whereas JCP&L's capital structure is dictated by the corporate parent. (RAIB at 9). Finally, the RPA argues that using a consolidated capital structure is consistent with the practices of credit reporting agencies, which, the RPA contends, rarely view regulated subsidiaries on a stand-alone basis. (RAIB at 10).

The RPA's proposed capital structure is significantly different than that of the Company and consists of 37.20% common equity, 5.40% preferred stock and 57.40% long-term debt. (R-41, BLC-1).

Staff

As set forth in its brief, Staff asserts that JCP&L should be viewed as a stand-alone company, whereby only the risks of JCP&L are relevant when estimating its cost of equity. Staff asserts that the risks faced by FirstEnergy and its major subsidiaries should not be reflected in the ratemaking process. (SIB at 15-17). In addition, the credit quality of JCP&L, as measured by debt ratings from Moody's, Fitch, and Standard & Poor's, should also be determined on a stand-alone basis. Staff asserts that if JCP&L's credit were viewed as independent of FirstEnergy, JCP&L would be better insulated from the harmful consequences that might result from downgrades of the credit quality of FirstEnergy or its unregulated subsidiaries. Staff asserts that this insulation is in fact required by the Board's Merger Order. (SIB at 17).

As for JCP&L's proposed changes to its capital structure, Staff asserts that in light of the reduced operating risks facing JCP&L and the very high coverages implied therein, adoption of JCP&L's recommendations would impose excessive costs on customers that are beyond those needed to retain investment grade ratings.

Staff recommends adoption of a less leveraged capital structure than that recommended by the RPA. Staff recommends a capital structure consisting of 46.00% common equity, 5.66% tax-deductible preferred ("MIPS") 0.57% preferred stock and 47.77% long-term debt. (SIB at 20, Table 1).

Staff argues that its proposed capital structure should provide, along with supportive regulation, a level of financial integrity sufficient to ensure an investment grade rating for JCP&L. Staff observes that its recommended capital structure is sufficient given the limited external capital requirements facing JCP&L, and that a 46% equity ratio is just about the same level allowed in JCP&L's last rate case when it had significantly higher risks, including full generation responsibilities. (SIB at 20-21).

Board Discussion and Analysis

It is well established that a public utility is entitled to such rates as will permit it to earn a return on the value of the property employed for the convenience of the public, equal to

[10] I/M/O the Board's Review of Unbundled Network Elements Rates, Terms and Conditions of Bell-Atlantic-New Jersey, Inc., BPU Docket No. TO00060356 (March 6, 2002)

that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923). With broad discretion the Board must determine what, in a particular situation, is a just and reasonable return for a public utility. Atlantic City Sewerage Co. v. Board of Public Utility Com'rs, 128 N.J.L. 359 (1942), aff'd 129 N.J.L. 401 (E&A 1943). Public utility rates are valid so long as they enable the utility to operate successfully, maintain its financial integrity, attract capital and compensate its investors for the risk assumed. FPC v. Hope Natural Gas Co., 320 U.S. 591, 605 (1944). In other words, if the total effect of the rate order is not unreasonable, judicial inquiry ends. Thus, a cost of equity figure is appropriate so long as it is "within the range of reasonableness, the zone between the lowest rate not confiscatory and the highest rate fair to the public." In re N.J. Power & Light Co., 9 N.J. 498, 535 (1952).

There is one further consideration with respect to rate of return. While repeating the fundamental principle that public utilities are to be granted just and reasonable rates for safe, adequate and proper service should not be a restatement of the obvious, apparently the ancient link between good service and rates is not as clear as it should be to all segments of the regulated community. This nexus is well settled both in New Jersey, e.g., I/M/O Petition of Valley Road Sewerage Co., 154 N.J. 224 (1998), and beyond, e.g., US West Communications, Inc. v. Washington Utilities and Transportation Comm'n., 134 Wash. 2d 74, 949 P.2d 1337 (1998).

The Board has issued three summary orders for PSE&G, RECO, and JCP&L. In each of those Orders, the Board made Findings with regard to the traditional rate case issue of Cost of Capital. The sub-issues related to the appropriate capital structure and the component costs for common equity and long-term debt. The records developed on these issues in each case are extensive and have provided the Board with sufficient information upon which the Board has relied in issuing FINAL DECISIONS AND ORDERS for Rockland and PSE&G.

The Board believes that the regulatory principles developed by the Staff and adopted by

During the course of litigating and deliberating on this case, the Board was compelled to deal with a number of operating problems directly attributable to JCP&L's failure to appropriately maintain system reliability. These recurring problems brought into sharp focus the potentially serious long-term negative impacts on their customers, the economy of their service territory, and on the confidence of ratepayers in the Board's ability to effectively regulate JCP&L. The Board cannot ignore these recurring reliability problems and determined to take immediate action to construct an interim remedial regulatory incentive mechanism.

The Board will use the allowed return on equity as the most direct and powerful signal that they can send to the company to improve their system reliability and do it as soon as practicable. The Board **ORDERS** that the Company's return on equity be reduced from the 9.75% allowed above to 9.50%, a reduction of 25 basis points, until such time as the Company provides sufficient evidence to the Board that they have made the necessary improvements required to maintain system reliability. The Company will be provided a full opportunity to make their case and reestablish 9.75% as their allowed return on equity. However, as noted in our Summary Order, if the Company does not meet these requirements ,..."the Board reserves its rights to take further appropriate actions, including, but not limited to, reducing the return on equity to as low as 9.25% from the date of this Order." The capital structure and the calculation of the cost of capital are shown in Exhibit appended to this Order.

Historically the allowed return on equity is one key measure used by the financial community in estimating the opportunity for the Company to earn a reasonable return on its regulatory rate base. Hopefully the prominence of this financial measure and the statutory mandate to provide safe, adequate and proper service will combine to provide the compelling incentives for the Company to restore system reliability.

After reviewing the record evidence on cost of capital and capital structure, the Board **ADOPTS** the analysis and resulting recommendations of Staff and **FINDS** that the appropriate return on equity for JCP&L should be set at 9.50% and JCP&L's overall cost of capital is 8.38%.

D. Cash Working Capital ("CWC") and Lead/Lag

Both JCP&L and the RPA utilized the lead/lag study method to determine JCP&L's cash working capital requirements. Staff agreed with JCP&L and the RPA that the lead/lag method is the most appropriate to use to determine the Company's revenue requirement. (SIB at 35). The cash working capital issues include 1) depreciation, 2) amortization expenses, 3) regulatory debits and credits, 4) deferred taxes, 5) tax credits, 6) JCP&L's common equity return and 7) JCP&L's payment of dividends on preferred stock and interest on long-term debt.

JCP&L

JCP&L included these items in its lead/lag study with a zero lag. (JC-11 Rebuttal at 5-7). JCP&L asserts that referring to these items as "non-cash" is misleading because it suggests that there is no cash outlay by investors. JCP&L asserts that the depreciation expense constitutes the required return of capital previously invested in plant and equipment which constitutes a major portion of its rate base, and which is reduced by the accumulated depreciation. Because investors must wait to receive the return-of-

capital cash payment of the depreciation expense in the form of utility revenues, there must be a CWC requirement to the extent of the revenue lag. (Ibid.).

JCP&L contends that deferred taxes are initially created to reflect timing differences between book depreciation and the tax depreciation expense on cash invested in utility plant, which are deducted from rate base. JCP&L argues that the level of deferred income taxes reflected on the income statement must be included in the CWC study with a zero lag in order to compensate investors for the lag in the recovery of current revenue related to that expense. (JC-11 Rebuttal at 6).

RPA

The RPA argues that these items are non-cash expenses and their inclusion in the lead-lag analysis overstates JCP&L's cash working capital requirement. (R-38 at 9-10). The RPA asserts that for these costs, the cash transaction has already occurred and that neither the deferred charges nor the other non-cash expenses requires a current cash outlay. Because no periodic cash outlay is required, no investment in working capital is required. This is especially true with respect to deferred taxes, which have been collected from ratepayers without being paid by the utility to the Internal Revenue Service. (Ibid.).

Staff

Staff recommends inclusion of these items in the lead/lag study with a zero lag as proposed by JCP&L with the exception of deferred taxes and tax credits. (SIB at 36). Staff recommends exclusion of deferred taxes and tax credits from the calculation of working capital as proposed by the RPA. Staff argues that there is a key distinction between depreciation and deferred taxes and asserts that although JCP&L's investors financed the construction of utility plant leading to the depreciation expense, deferred taxes arise more from timing differences associated with the tax code than an outlay of investor capital. Staff supports its analysis by referencing several prior Board decisions.[11] (SIB at 36-37).

Board Discussion and Analysis

In I/M/O Public Service Electric and Gas Company for an Increase in Rates, BPU Docket No. ER85121163, dated April 6, 1987, the Board adopted that portion of the ALJ's recommendation regarding the assignment of a zero lag in the lead/lag study to the Company's depreciation expense. The Board concurs with the ALJ's findings on this issue, specifically, where the ALJ found:

[11] I/M/O Public Service Electric and Gas Company for an Increase in Rates, BPU Docket No. ER85121163, (April 6, 1987); I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, (June 6, 2001); I/M/O Public Service Electric & Gas Company for an Increase in Rates, BPU Docket No. ER85121163, (April 6, 1987); I/M/O Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR88121321, (February 1, 1990).

> Staff advances the position that the investors should be compensated for the revenue lag in the recovery of depreciation expense and the amortization of owned nuclear fuel. This is true since the Company's investors have financed the construction of plant and the purchase of nuclear fuel.
>
> The Company should be allowed to earn a return on these funds until the dollars are actually returned to the investor. The return on the investment is accomplished over the period of time the investment benefits ratepayers through their payment of annual depreciation and the amortization expense. Ratepayers have been overcompensated. At the time the items are reflected on the books, the cash associated with those items has not been returned to the investors. Accordingly, the only way to adjust for this factor is to assign a zero lag in the lead/lag study to the depreciation expense and the amortization of owned nuclear fuel. This appropriately reflects the fact that the collection of revenue lags behind the provision of service by 42.2 days.
>
> [Initial Decision in I/M/O Public Service Electric and Gas Company for an Increase in Rates, BPU Docket No. ER85121163 at 33]

This finding was also upheld in the Board's Order in I/M/O Middlesex Water Company for approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, dated June 6, 2001, where the Board stated, "the Board ADOPTS the position of the Staff and the Company, consistent with prior Board findings, that depreciation should be included in the lead/lag study and assigned zero days." Id. at 17.

As to the treatment of deferred income taxes in the lead/lag study, in I/M/O Public Service Electric & Gas Company for an Increase in Rates, BPU Docket No. ER85121163, dated April 6, 1987, the Board adopted that portion of the ALJ's recommendation on this issue where the ALJ found:

> I FIND that deferred taxes should be excluded from the lead/lag study because they did not, at any point in time, require investor-supplied capital. It would be unreasonable and inappropriate to force ratepayers to pay a return on funds not supplied by investors.
>
> [Initial Decision in I/M/O Public Service Electric & Gas Company for an Increase in Rates, BPU Docket No. ER85121163 at 35.]

The Board affirmed this policy in I/M/O Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions,

BPU Docket No. GR88121321, Final Order dated February 1, 1990, where the Board found:

> The ALJ was persuaded by Staff's argument as to the proper ratemaking treatment for deferred taxes. The ALJ recommended that deferred taxes be deducted from operating revenues in the working capital allowance for purposes of this proceeding. The Board FINDS the ALJ's determination on deferred taxes to be reasonable and consistent with Board policy. Therefore, the Board ADOPTS the ALJ's conclusion on this issue.
>
> [Id. at 7].

The Board **ADOPTS** Staff's recommendation that these items be included in the lead/lag study and assigned a zero lag as proposed by the Company with the exception of deferred taxes and tax credits. The Board further **ADOPTS** Staff's recommendation that deferred taxes and tax credits be excluded from the calculation of working capital as proposed by the RPA. The Board **FINDS** that there is a key distinction between depreciation and deferred taxes. The Company's investors have financed the construction of plant, which led to the depreciation expense. However, the deferred taxes more succinctly arise from timing differences associated with the [redacted]

In addition, the RPA argues that JCP&L should not have lumped long-term debt interest and preferred stock dividends with the common equity return and applied a zero-day lag. (R-38 at 11). According to the RPA, there are contractual requirements associated with debt interest and preferred stock dividends that obligate JCP&L to make specified payments on certain dates. In this respect, debt interest and preferred dividend elements of JCP&L's return more closely resemble its other cash operating expenses. Further, where these items fall on the income statement is irrelevant; the Company has had the use of those funds until it pays the investor or stockholder and that time period should be reflected in the lead-lag study. (5T:104-6 to 105-4). The payment leads for long-term debt interest and preferred stock dividends should be separately recognized in the lead-lag calculation. The RPA calculates a 91.25-day expense lead for debt interest, which is paid semi-annually, and a 45.63-day expense lead for preferred stock dividends, which are paid quarterly, and includes these in its lead-lag calculation. (Ibid.; R-38, 11).

Staff

Staff recommends, consistent with prior Board decisions,[12] inclusion of the return on invested capital in the lead/lag study and assigning a zero lag as proposed by the Company. Staff believes that investors are entitled to earn a return as service is rendered through the cash working capital requirement for the use of their funds while they are retained in the business. (SIB at 41-42).

Board Discussion and Analysis

The Board **ADOPTS** Staff's recommendation that the return on invested capital be included in the lead/lag study and be assigned a zero lag as proposed by the Company. The Board **FINDS** that investors are entitled to earn a return as service is rendered, that is, daily. Stockholders are entitled to compensation through the cash working capital requirement for the use of their funds while they are retained in the business. This finding is consistent with Board policy regarding this issue. Specifically, in I/M/O New Jersey Natural Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR89030335J, Final Order dated July 17, 1990, the Board noted:

> The ALJ accepted the Company and Staff's position as to the proper ratemaking treatment to be accorded return on invested capital. The ALJ was persuaded that ample Board precedent supports the position that the return on invested capital should be included in the lead/lag study with a zero lag. We agree and have held that the return on invested capital should be assigned a zero lag.
>
> [Id. at 15].

[12] I/M/O New Jersey Natural Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions, BPU Docket No. GR89030335J (July 17, 1990); and I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, (June 6, 2001).

It is also consistent with the Board's decision in I/M/O Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362, dated June 6, 2001 in which the Board stated: "The Board REJECTS the RPA's position that the return on common equity should be removed from the lead/lag study." Id. at 17.

F. Consolidated Tax Adjustment

JCP&L

JCP&L's former parent company, GPU, Inc., included JCP&L in its consolidated federal income tax filing along with GPU's other subsidiaries. (JC-4, Schedule RFP-2; R-38). As a result of making a consolidated tax filing, GPU as a whole paid less federal income taxes than it would have if each subsidiary filed separately, thus producing a tax savings. In this proceeding, JCP&L proposes that none of the consolidated tax savings flow to JCP&L's customers. Instead, these tax saving would all flow to the loss affiliates. Essentially, JCP&L proposes that its rates be set in this proceeding as though JCP&L paid its taxes on a stand-alone basis. The Company argues that there is no basis for any prospective consolidated tax savings adjustment because the unregulated affiliates had a cumulative positive taxable income during the period in question and the tax savings could have been produced by offsetting the tax losses by the positive income of the unregulated companies. JCP&L argues that the loss [illegible]

Both Staff and RPA recommend that a "rate base" methodology be used to calculate consolidated tax savings in this proceeding. (SIB at 46-47). Staff notes that the IRS has found that the rate base method does not violate IRS normalization requirements. The rate base methodologies proposed by the Staff and RPA differ slightly in that the RPA calculates the savings on a yearly basis, while Staff looks at the data over the entire period. Staff believes that its proposed methodology is appropriate, because it was previously approved by the Board and allows for the fact that a company could utilize its net operating loss on a stand-alone-basis under the carry back and carry forward provisions of the Internal Revenue Code. Staff recommends that the Board order a consolidated tax savings adjustment in the amount of $36.9 million.

Board Discussion and Analysis

As a result of making a consolidated tax filing during the years 1991-1999, GPU, JCP&L's parent company during that time period, as a whole paid less federal income taxes than it would have if each subsidiary filed separately, thus producing a tax savings. The law and Board policy are well-settled that consolidated tax savings are to be shared with customers. I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service, Phase II, Docket No. ER90091090J (Order dated October 20, 1992) ("1992 Atlantic Electric Order"); I/M/O the Petition of Jersey Central Power and Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, Docket No. ER91121820J (Order dated June 15, 1993) ("1993 JCP&L Order"). Moreover, the New Jersey courts have confirmed that the BPU has "the power and the function to take into consideration the tax savings flowing from the filing of a consolidated return and determining what proportion of the consolidated tax is reasonably attributable to [the utility]." Lambertville Water Company v. New Jersey Bd. Of Public Utility Com'rs, 153 N.J. Super. 24, 28 (App. Div. 1977), reversed on other grounds, 79 N.J. 449 (1979), (citing FPC v. United Gas Pipe Line Co., 386 U.S. 237, 87 S.Ct. 1003, 18 L.Ed.2d 18 (1967).

In the Board's 1993 JCP&L Order, supra, the Board clearly explained that:

> The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. Income from utility operations provides the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment. The issue, in this case, is not whether such an adjustment should be made, but rather, what methodology should be used to make such an adjustment. In this area, the courts have held that the Board has power and discretion to choose any approach which rationally

> determines a subsidiary utility's effective tax rate. Toms River Water Company v. New Jersey Public Utilities Commissioners, 158 N.J. Super. 57 (1978).
>
> Based on our review of the record in this case, the Board **REJECTS** the ALJ's recommendation to accept the income tax expense adjustment proposed by Petitioner and, instead **ADOPTS** the position of Staff that the rate base adjustment is a more appropriate methodology for the reflection of consolidated tax savings. The rate base approach properly compensates ratepayers for the time value of money that is essentially lent cost-free to the holding companies in the form of tax advantages used currently and is consistent with our recent Atlantic Electric decision (Docket No. ER9009190J). Moreover, in order to maintain consistency with the methodology applied in the Atlantic decision, we modify the Staff calculation and find that a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case.
>
> [1993 JCP&L Order at pages 7-8].

Therefore, the question to be addressed by the Board in this proceeding is how these tax savings should be allocated among the affiliated companies and based upon this allocation whether or not an adjustment is appropriate in this case. JCP&L believes that a consolidated tax savings adjustment is not appropriate in this case because over the time in question, offsetting the tax losses by the positive income of only unregulated companies could have produced the tax savings. (PIB at 60). JCP&L further objects to the RPA' s adjustment in this proceeding stating that it is an ongoing, permanent rate base deduction that would remain forever, with no hope of ever turning around even if and when the utility's affiliates all consistently reported positive taxable income. (PIB at 61). The Board believes that Staff correctly points out that allocating all of the savings to the unregulated affiliates, as proposed by JCP&L in this proceeding, would be as arbitrary and unfair as it would be to allocate the entire savings to the regulated companies.

Regarding the specific methodology for calculating the consolidated tax savings, the Staff and RPA recommend that, in this proceeding, the "rate base" methodology be used to calculate any consolidated tax savings. (RAIB at 37-38; R-38, p. 16 Schedule 2, p.3; SIB at 46-47). However, the rate base methodologies proposed by the Staff and RPA differ in that the RPA calculates the savings on a year-by-year basis, where as Staff's methodology looks at the data over the entire period. Under Staff's methodology if a company has positive taxable income in some years and taxable losses in other years during the period analyzed, it will be able to offset its tax losses to the extent that it has sufficient taxable income in other years rather than having them shared amongst the positive companies. Staff believes this is appropriate, because it takes into account the fact that this type of company could utilize its net operating loss on a stand-alone-basis under the carry back and carry forward provisions of the Internal Revenue Code. (SIB at 47).

The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. The consolidated tax savings in question could not be achieved without the income of the affiliates with positive income and it would not be equitable to say that it was achieved by using the positive income of some companies but not others. Therefore, the tax savings should be allocated to each of the affiliates with positive income by their percentage share of positive income regardless of whether or not they are regulated or unregulated. Based upon this method of allocation, and JCP&L's percentage of positive income, it is clear that JCP&L did in fact significantly contribute to the consolidated tax savings through its positive taxable income. Further, the rate base approach recommended by Staff properly compensates ratepayers for the time value of money that is essentially lent cost-free to its affiliates in the form of tax advantages used currently and takes into account the fact that loss affiliates could utilize their net operating loss on a stand-alone-basis under the carry back and carry forward provisions of the Internal Revenue Code. Therefore, the Board **FINDS** that the methodology utilized by Staff and shown on Attachment A[14] to calculate consolidated tax savings is correct and **ADOPTS** the position of Staff that a consolidated tax savings adjustment in the amount of $36.9 million be made to the Company's rate base.

G. Revenue Annualization

JCP&L

JCP&L's weather normalization adjustment submitted in its 12+0 update decreases actual test year revenues by $13,106,000. As part of its adjustment, JCP&L uses an average customer level for the test year and does not account for any growth in the number of customers.

JCP&L rebuts the RPA's customer annualization adjustment, arguing that the RPA assumes growth for residential and commercial customers, but ignores the 1.0% erosion of JCP&L's industrial customer base. JCP&L also argues that it does not annualize its expenses to year-end levels but only annualized depreciation. (JC-4, at 2-3).

RPA

The RPA proposes an adjustment for customer growth to residential and small commercial customers based on growth rates of approximately 0.6% and 0.9% over the average number of year-end customers, resulting in an increase to the test year revenue for the residential and small commercial customer classes. (R-38 at 18). The RPA argues that failure to annualize customer growth occurring during the test year distorts the measurement of the income-producing capability underlying utility assets and overstates JCP&L's revenue requirement. The RPA's 12+0 year-end revenue annualization adjustment reflects a $2,255,000 adjustment for Residential customers and a $2,429,000 adjustment for General Service Secondary customers, for a total annualization adjustment of $4,684,000 to test year revenues. (R-38, DEP-1 (12+0), Schedule 3 at 3).

Staff

[14] Appendix SIB-1 to Staff's Initial Brief, Schedule S-Rev-4.

Staff notes that JCP&L used the year-end plant-in-service balance and annualized its depreciation expenses based on year-end plant. (JC-4 at 1-2). Staff asserts that in order to properly match revenues with test-year end rate base and annualized depreciation expenses based on year-end plant, revenues should reflect customer growth up to the end of the test year. (SIB at 50). Staff notes that the BPU has used this approach in previous base rate cases. (Ibid.).

Board Discussion and Analysis

Consistent with prior findings in other matters before the Board, the Board **HEREBY ADOPTS** the recommendation of Staff and the Ratepayer Advocate to include a $2,255,000 adjustment for Residential customer growth based upon a rate of 0.6% and $2,429,000 for General Service Secondary customer growth based upon a rate of 0.9%. The Board **HEREBY FINDS** the inclusion of revenues related to such growth is appropriate when matching revenues with the use of test-year end rate base and annualized depreciation expenses based on year-end plant. Also, as noted by Staff, the Company's argument that such an adjustment is selective as it includes customer growth for residential and commercial customers but ignores the erosion of the industrial customer base must be given little weight by the Board because the Company did not provide any alternative adjustment to reflect end of test year customer levels.

H. Clean Energy Program ("CEP") [Formerly "Comprehensive Resource Analysis"] - Lost Revenue Annualization

JCP&L

JCP&L proposes a test year revenue normalization adjustment of ($722,459), which reflects an annualization of CEP lost revenues associated with Board-approved energy efficiency programs implemented during the test year and included in JCP&L's proposed delivery charge. (JC-3 at 26). JCP&L asserts that its proposed adjustment to test year revenues is appropriate because the Board's DSM regulations permit the timely recovery of lost revenues and allow each utility to propose for consideration a mechanism to recover lost revenues. (JC-3 Rebuttal at 7). JCP&L asserts that lost revenue recovery for CEP programs is consistent with the Board Order in I/M/O the Petition of the Filings of the Comprehensive Resource analysis Energy Programs Pursuant to Section 12 of the Electric Energy Discount & Energy Competition Act of 1999, Docket Nos. EX99050347, EO99050349 et al., dated March 9, 2001, which adopted a utility proposal for CEP lost revenue recovery.

RPA

The RPA recommends that there be no annualized adjustment for CEP lost revenues in the 2002 test year, nor should CEP lost revenues be booked to the Demand Side Factor ("DSF") component of the SBC after 2002. (R-69 at 7-8). The RPA contends that utility recovery of CEP lost revenues is inappropriate because the Board has not approved the methodology for calculating savings and lost revenues, and because the proposed measurement protocols that have been submitted to the Board by the utilities would significantly overstate the impact on energy savings from new CEP programs. (R-69 at 9).

Staff

Staff agrees with the RPA that until the Board has made a final determination as to which programs, if any, qualify for lost revenue recovery and the methodology to calculate lost revenues associated with the CEP programs, the proposed annualized revenue adjustment of ($722,459) should not be included in the calculation of the delivery charge. The issue of measurement and verification of protocols remains pending before the Board, and Staff is still in the process of accurately verifying and measuring savings resulting from the implementation of energy programs. Until this review is completed, and until the Board has made a determination whether it is appropriate for the utilities to recover lost revenues, Staff recommends that JCP&L's requested recovery of lost revenues be denied.

Board Discussion and Analysis

The Board has not yet approved the appropriate protocols for verification and measurement of energy savings due to the Clean Energy Programs. However, until the Board has made a final decision regarding the measurement and verification protocols and appropriateness of the recovery of lost revenues pertaining to the Clean Energy Program, the Board **HEREBY FINDS** that JCP&L is permitted to defer its alleged lost revenues, as was recently approved by the Board in PSE&G's base rate case dated July 31, 2003, Docket No. ER02050303, et al. This would allow JCP&L to defer its lost revenues from May 2001 based on JCP&L energy savings as reported in the quarterly New Jersey Clean Energy Program reports filed with the Board, and subject to review by the Office of Clean Energy. If the Board subsequently determines in an appropriate proceeding that lost revenues are recoverable, the Company may file a Petition requesting recovery.

I. Charitable Contributions

JCP&L

The Company proposes to reclassify estimated contributions to charitable organizations from income deductions to operation expense resulting in a $752,000 adjustment to the Company's pro forma operating expenses. (JC-4 at 4, Schedule RFP-2, (12+0), JC-75). The Company argues that the bulk of these charitable contributions will be made by the FirstEnergy Foundation, which is a charitable foundation that supports non-profit, tax-exempt organizations in the service territories of the various utilities owned by FirstEnergy Corporation. (Ibid.). The Company asserts that most of the direct recipients of JCP&L's contributions are themselves customers of JCP&L and that all contributions reflected in the Company's proposed adjustment are targeted for New Jersey-based organizations. (JC-4 at 4-5). Pursuant to the Merger Order, the proposed adjustment does not include technology grants made to New Jersey schools and libraries.

JCP&L asserts that the RPA misapplies the NJAWC case, I/M/O the Petition of New Jersey American Water Company, Inc. for an Increase in Rates for Water and Sewer Service and Other Tariff Modifications, 169 N.J. 181 (July, 2001) arguing that the Court's opinion was premised on a finding that the Board's prior policy was arbitrary and not supported by the record in that case. JCP&L notes that it supports charities such as the United Way, youth programs, scholarship funds and other entities that are clearly consistent with the interests of its ratepayers and the communities in which they live. In

addition, the Company's contributions to the American Red Cross, and local police, fire and emergency services directly benefit its customers and the communities they live in by increasing safety in these uncertain times. JCP&L notes that the Merger Order requires it to maintain its charitable commitments for three years after the merger. JCP&L asserts that the record in this proceeding provides the requisite factual support that was lacking in the NJAWC case.

RPA

The RPA opposes the Company's proposed adjustment for charitable contributions arguing that New Jersey American Water Company compels exclusion of charitable contributions from JCP&L's pro forma operating expenses.

Staff

Staff agrees with the RPA's interpretation of the opinion and recommends that charitable contributions be excluded from JCP&L's pro forma operating expenses. Staff rejects the argument by the Company that would narrow the ruling of the Court. Staff believes that the Court's clear language, strong expression of equitable considerations supported by decisions and opinions from courts of other jurisdictions provide an unambiguous and unmistakable directive compelling a broad reading of the Court's Opinion.

Board Discussion and Analysis

As noted by Staff, the New Jersey Supreme Court indicated "on general fairness grounds, the ratepayers should not be forced to pay additional amounts for charitable purposes at the hands of a regulated monopoly." I/M/O the Petition of New Jersey American Water Company, Inc. for an Increase in Rates for Water and Sewer Service and Other Tariff Modifications, 169 N.J. 193. It also emphasized "because a utility's charitable contributions are discretionary, they are more appropriately borne by the utility's shareholders, not its captive ratepayers." (Id. at 193) Accordingly, the Board agrees with the Ratepayer Advocate and Staff and **HEREBY FINDS** that all charitable contributions must be excluded from the Company's operating expenses.

J. Depreciation

Background

By letter dated March 1, 1995, JCP&L filed with the Board pursuant to 48:2-18 and N.J.A.C. 14:11-1.12 a petition seeking approval of changes to JCP&L's existing rates of depreciation on certain classification of its utility property ("1995 Depreciation Filing).[15] (JC-60). The Company did not seek any rate treatment for the proposed higher net amount of current depreciation expense that would result from the proposed changes but did reserve its right to seek prospective recovery of any new level of expense as part of its next base rate proceeding. Specifically, JCP&L requested the Board's approval of proposed changes to the Company's annual depreciation accrual rates and methodologies. The changes proposed by the Company would result in a decrease of

[15] In the Matter of the Petition of Jersey Central Power & Light Company for Approval of Changes to its Rates of Depreciation on Certain Classifications of its Utility Property Pursuant to N.J.S.A. 48:2-18 and N.J.A.C. 14:11-1.12, BPU Docket No. EO95030098, June 27,1996, March 24, 1997.

$8.6 million in accruals for its transmission and distribution plant, a decrease of $0.2 million in its general plant accrual (based on the FERC-approved change in accounting methodology), and an increase in the nuclear plant accrual of $10.2 million. The overall result of the proposed changes would be a net increase of $1.4 million to its annual depreciation accrual.

The 1995 Depreciation Filing was resolved by a Stipulation of Settlement ("Depreciation Stipulation") by the parties to the proceeding consisting of the Company, Board Staff and the Ratepayer Advocate and approved by the Board by Summary Order dated March 24, 1997.

JCP&L

JCP&L requests a net depreciation expense annualization adjustment of $1,515,000 and a total annualized depreciation expense of $114,847,000, which equates to an average overall depreciation rate of 3.39%, based upon depreciable plant (transmission, distribution, and general plant as of December 31, 2002). JCP&L reflects depreciation rates of 1.86% for transmission plant, 3.53% for distribution plant and 5.91% for general plant. (JC-25, JC-4 Schedule RFP-2 (12+0) at 6). The Company maintains that its proposal complies with paragraph 17 of the June 27, 1996 Depreciation Stipulation approved by the Board, by updating the book depreciation rate computations annually for plant additions, retirements, transfers and adjustments and keeping the negative net salvage rate percentages and depreciation service lives consistent with the separate Stipulation of Settlement of Depreciation Rates, also dated June 27, 1996, which also was approved by the Board as part of a Global Settlement.[16] (JC-17 at 5). JCP&L did not request or submit a depreciation study in this proceeding to change the negative net salvage percentages or service lives that were fixed in those stipulations approved by the Board. (Ibid.).

In response to the RPA's criticisms, JCP&L presented its witness Timothy H. Schad. Mr. Schad, a certified public accountant who has experience as a auditor with the Federal Energy Regulatory Commission ("FERC") and as a utility specialist in FERC's Office of Electric Power Regulation, testified that Financial Accounting Standard ("FAS") 143 does not impact the Board approved transmission, distribution, or general plant depreciation rates, including any negative net salvage components. [illegible]

The Company faulted the recommendation of RPA witness, Michael J. Majoros to capitalize the cost of removal as part of the cost of the replacement plant, gleaning from Mr. Majoros that he "was not sure or could not "recall any instance" where the Board ever approved such an approach. (PIB at 99, citing 9T101:2-16; JC-62). Additionally, Mr. Majoros acknowledged that the National Association of Regulatory Utility Commissioners (NARUC") in its published depreciation manual entitled "Public Utility Depreciation Practices" ("Depreciation Manual") supports the inclusion of future net salvage and cost of removal in current depreciation rates (PIB at 99-100, citing 9T103:2 to 104:1) and that the Board has adopted the principles set forth in the NARUC Depreciation Manual and includes future negative net salvage in the calculation of depreciation rates for New Jersey utilities. (PIB at 101, citing 9T118:11 to 119:14, See also New Jersey Natural Gas Company, BPU Docket No. GR8510974, June 20, 1986 [76 PUR 4th 605 [[1986]]). Furthermore, Mr. Majoros admitted that "many, if not most", regulatory commissions allow future negative net salvage or cost of removal in depreciation accrual rates for public utilities. (PIB at 100, citing 9T104:2-7). Mr. Majoros also admitted that the FERC Uniform System of Accounts recognizes salvage value and cost of removal as part of the setting rates for depreciation. (Id. citing 9T106:7-18).

RPA

According to the RPA, the Company's depreciation expense is recovered by the Company in rates on a virtual dollar for dollar basis. (RAIB at 76). The RPA asserts that based on its analysis, the principle depreciation issue is the ratemaking treatment to be allowed by the Board for the Company's estimated future net salvage, as it pertains to the Company's annual depreciation expense. Additional issues raised by the RPA are whether the Board should require the Company to submit a report describing all aspects of its depreciation rate update calculations, and whether, on a going forward basis, the cost of removal of an asset should be charged to the cost of replacement of that asset. (Ibid.)

The RPA contends that JCP&L's test year depreciation rates are excessive because they include an unsupportable and unreasonable request for negative net salvage (cost of removal). (RAIB at 77). According to the depreciation witness for the RPA, Michael J. Majoros, Jr., the Company proposes to collect $43.1 million for negative net salvage recovery in its test year depreciation expense for transmission, distribution and general plant. (RAIB at 77 citing R-64 at 12). Yet a review by Mr. Majoros over a five-year period ending 2001, showed that the Company had an average annual net negative salvage of only $3.9 million. (Ibid. citing R-64 at 17). This figure may be inflated since it includes production plant salvage and cost of removal, which function was removed from the Company and its rates pursuant to the Board Order in JCP&L's restructuring proceeding. (Ibid.) The RPA argues that this figure is further increased through the inclusion by the Company of future inflation in its estimated net salvage expense which is eventually recovered by the Company in its rates. (Id. at 78, citing R-64 at 13). Mr. Majoros recommends removing JCP&L's net salvage from its depreciation rate calculations, and replacing it with the five-year rolling average "net salvage allowance approach" used by the Pennsylvania, Kentucky, and Missouri Public Utility Commissions. (Ibid. citing R-64 at 17). Under this methodology, net salvage ratios are not calculated or included in depreciation rates, being replaced with a separate five-year average calculation of net negative salvage which is then added to the annual depreciation expense and included in the reserve. The RPA sees this approach as

comparable to including a normalized expense into a utility's revenue requirement. (RAIB at 78).

The RPA argues that its recommended net salvage allowance approach is an approach recognized by the National Association of Regulatory Utility Commissioners ("NARUC") (R-66 at 158) and that its use in this proceeding fits squarely within the rationale contained in NARUC's depreciation manual.

The RPA further asserts that JCP&L's net salvage proposal is inconsistent with the principles regarding cost, capital recovery, and cost of removal. Specifically, pursuant to FAS143, the RPA contends that all companies must determine if they have actual legal obligations to remove retired assets. (RAIB at 39). If there is such an obligation, it is considered to be part of the cost of the asset. Here, however, JCP&L included negative net salvage in its depreciation rates, despite not having identified any associated AROs. (R-64 at 13 to 14). The RPA acknowledges that FAS 143 has not yet been adopted as a Generally Accepted Accounting Principle, but notes that the FERC is presently contemplating changes to the Uniform System of Accounts to recognize FAS 143. (R-64 at 14). The RPA believes that, in the absence of an ARO, the costs should be capitalized as part of the replacement to which they relate, or charged to expense in the case of abandonment, but not treated as part of the cost of the asset in a depreciation rate calculation because, in either case, by definition, there is no cost. (R-64 at 15).

The RPA argues that JCP&L's test year depreciation rates are different from the depreciation rates approved by the Board. (R-64 at 4). The RPA believes that JCP&L should submit a report to the Board and to the RPA providing all of the calculations underlying the annual filed updates. (R-64 at 5-6). The RPA contends that JCP&L calculated its test year depreciation rates using December 31, 2000 plant reserve balances. This is inappropriate because JCP&L now makes annual updates to its depreciation rates pursuant to the aforementioned stipulation.

The RPA asserts that JCP&L should be required to submit a report to the Board and the RPA by February 28 of each year identifying all aspects of its depreciation rate update calculations. (R-64 at 19). The RPA's updated exhibits propose a decrease of $37.701 million to JCP&L's updated 12-0 request. (R-38, DEP-1 (12+0), Schedule 3 at 2). This reflects the application of the RPA's proposed depreciation rates to JCP&L's updated plant balances at December 31, 2002, and the allowance of $4.8 million for the cost of removal, as reflected in JCP&L's test year budget for transmission, distribution and general plant.

Staff

Staff recommends adoption of the RPA's proposed depreciation rates which it believes is supported by FAS-143 and the concept of unbundled depreciation rate or rates that exclude the provision of the embedded cost of removal. (SIB at 91). Staff believes, however, that the cost of removal expense provision should reflect a broader (10-year) window of actual experience rather than the 5-year rolling average proposed by the RPA. Staff noted the RPA's observation that such data is problematic in this case because it includes production plant salvage and the cost of removal. (Ibid.). For purposes of the calculation in this proceeding, Staff agrees with the RPA's witness, Michael Majoros recommended level of $4.8 million as a net salvage allowance. Staff

accepts the RPA's recommended depreciation expense of $77,146,000, resulting in an income adjustment of $22,300,000. (Ibid.).

Staff also concurs with the RPA that JCP&L should be required to submit an annual report to the BPU and the RPA providing all aspects of its depreciation rate update calculations. Staff accepts JCP&L's suggestion that the filing date be consistent with the filing date of its Annual Report to the Board. (Ibid.).

Board Discussion and Analysis

Net salvage refers to the difference between the gross salvage and the cost of removal of the plant. Gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. The cost of removal is connected to disposing of retired depreciable plant. Net salvage is positive when gross salvage exceeds cost of removal. Conversely, net salvage is negative when cost of removal exceeds gross salvage. A positive net salvage ratio reduces the depreciation rate and depreciation expense, while a negative net salvage ratio increases the depreciation rate and depreciation expense. In this matter, the RPA showed that the Company has incorporated $43.1 million of annual negative net salvage (cost of removal) recovery in its test year depreciation expense based upon currently approved depreciation rates, but over the five years ending 2001, the Company only experienced $3.9 million in negative net salvage on average, which amount includes net salvage on production plant that is not part of this case. As a result of this data and the underlying concept of FASB 143 as discussed in this matter, the Board **FINDS** it appropriate to revisit the concept of including estimated future net salvage in current depreciation rates. The Board **HEREBY FINDS** the recommendation of the Ratepayer Advocate and Staff to exclude estimated net salvage from depreciation rates to be appropriate. The Board **FURTHER FINDS** that the Ratepayer Advocate and Staff's proposed utilization of a five-year average of actual salvage expense in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. The Board concurs with Staff that the ten-year window of actual experience rather than the five-year rolling average proposed by the Ratepayer Advocate is appropriate. However, based upon the record in this matter as discussed above, the Board **HEREBY ADOPTS** a net salvage allowance of $4.8 million, which is the cost of removal reflected in the Company's test year budget.

K. Management Audit Expense: Amortization of Consultant Fees

JCP&L

JCP&L proposes a $142,000 increase to its test year operating expenses of $687,000, for a total annual amortization expense of $829,000, related to the recovery of Board-ordered management audit consultant fees. The resulting proposed amortization expense of $829,000 recognizes a three-year $519,000 annual amortization totaling $1,557,000 for expenses incurred for normal, periodic management audits for the years 1998 – 2002, and a four-year $310,000 annual amortization totaling $1,238,000 for expenses incurred for an extraordinary, one-time restructuring management audit.

RPA

The RPA recommends reducing JCP&L's test year management audit expenses by $100,000 related to the Phase 3 Outage Investigation Audit, and by $344,000 related to the Company's Reliability Audit. The RPA's proposal results in a $148,000 ($444,000/ 3 years) annual decrease in the Company's proposed expense, based on JCP&L's proposed three-year amortization for such expenses. The RPA reasons that JCP&L's actions preceding the outages were imprudent and that had it not been for those imprudent actions, the Phase 3 Outage investigation and the reliability audits would not have been necessary.

Staff

Staff disagrees with the RPA's disallowance of certain management audit expenses. Staff recommends a four-year amortization of the total audit expenses of $2,795,000 consistent with its use of a four-year amortization period for other items, such as rate case expenses. Staff recommends a total annual amortization expense of mandated management audits of $698,750, resulting in a net income adjustment of $77,000.

Board Discussion and Analysis

The Board **HEREBY FINDS** that a four-year amortization of the total mandated management audit expenses of $2,795,000, resulting in an annual amortization expense of $698,750, is appropriate in this matter. The Board agrees that a four-year amortization is reasonable for the Company to receive this level of management audit expenses, and is consistent with amortizations periods applied to other expenses in this matter. Consistent with N.J.S.A 48:2-16.4, the Board **FINDS** these costs reasonable for recovery on a four-year basis. The Board **HEREBY FINDS** no basis for disallowance of recovery of expenses incurred in association with the Company's Phase 3 Outage Investigation Audit and the Company's Reliability Audit as proposed by the Ratepayer Advocate.

L. GPU-FirstEnergy Merger Cost Accounting

JCP&L

In 2001, as part of the settlement and Board Order ("Merger Order") resolving JCP&L's merger proceeding, the Company wrote-off $300 million in funds accrued to the Company's Market Transition Charge/Basic Generation Service Deferred Balance.[17] (PIB at 73). The Company asserts that the $300 million write-off was intended to flow to the Company's customers savings anticipated from the merger and that this flow through of merger savings was made before such savings were actually realized. (Ibid.). The Company's shareholders were also allocated a portion of the net merger savings. JCP&L argues that the $300 million represents an actual amount the JCP&L paid to its energy suppliers

$35,019,000 of merger related costs incurred prior to the test year. JCP&L maintains that the recovery of these costs, including cost incurred prior to the test year consisting primarily of employee separation and information systems modification costs, (Id. at 76, citing JC-4 Rebuttal at 6) is justified because these costs were necessary to achieve the total merger savings that appeared in the test year. (Ibid., citing JC-81). JCP&L argues that the write-off mandated by the Merger Order provided $300 million of merger savings to customers, which constitutes an amount at least equal to all the merger savings that the Board deemed appropriate for allocation to customers and included the savings projected for 2002 and for many years beyond. (Ibid.). Accordingly, JCP&L argues that any additional net merger savings provided to its customers as part of this proceeding is improper since it would duplicate the savings already provided as part of the 2001 write-off and in effect "constitute a 'double helping' of merger savings" for its customers. (Ibid.).

RPA

The RPA asserts that JCP&L's proposal to recover any of the subject merger related costs is contrary to the Board's Merger Order and the Stipulation signed by the parties in that proceeding. (RAIB at 56, citing R-38 at 22). The RPA alleges that the Board's Merger Order specifically excluded recovery by the Company of certain merger related costs. According to the RPA the Company's ratepayers were not to include in their rate the following merger related costs: 1) consultant fees (including fees associated with financial, accounting, tax, and other services); 2) investment banker fees; 3) legal; 4) shareholder meeting and proxy expenses; 5) regulatory commission filing fees; 6) executive separation expenses; and 7) facilities, transportation and employee related costs. (RAIB at 57).

The RPA contends that the Board specifically accounted for merger related costs in its allocation to ratepayers of $300 million of an estimated $400 million of net merger savings and that, had the Board envisioned merger related costs as part of a future proceeding, it would have provided for a substantially greater allocation of gross merger savings in the merger proceeding, which then could arguably have been offset by the anticipated costs to achieve such savings. The RPA argues that approving JCP&L's request would allow JCP&L a double recovery of its merger related costs. (Id. at 58 citing R-38 at 22).

Staff

Staff notes that the Company identified and seeks recovery of merger related costs that were incurred in the test year and prior to the test year. (SIB at 61). The Staff disagrees with JCP&L's proposed treatment of merger related costs, including the proposed test year expenses, capital cost, and expenses incurred prior to the test year.

Based on the Staff's review of the Board's Merger Order, the Staff believes that the Board clearly ordered that $300 million of net merger saving be allocated to the Company's ratepayers at the conclusion of the merger proceeding. (SIB at 62-63). Staff thus agrees with the RPA that when the Board ordered the allocation of $300 million of the estimated $400 million in net merger savings to JCP&L's customers at the end of the merger proceeding, the Board envisioned that those net merger savings included the recovery of the estimated costs of achieving the gross level of merger savings over time. (SIB at 63). The Staff reasoned that if the Board intended to allow the Company to recover merger related costs a part of a future proceeding, then the

Board would have provided for a substantially greater allocation of gross merger saving in the merger proceeding. The Staff believes that in this way any future anticipated costs to achieve would be used as an offset to any gross savings. (SIB at 62-63).

Staff asserts that JCP&L's request for $35.019 million of pre-test year merger costs is flawed because: (1) it effectively seeks deferred accounting treatment of expenses on a retroactive basis; (2) it seeks treatment of merger costs that are already accounted for in the Board's implementation of net merger savings in the Merger Order, and (3) the approval of the request would build into JCP&L's rates an annual, recurrent recovery of costs that were actually incurred on a one-time basis to effectuate merger savings. Staff also asserts that JCP&L's request for recovery of $7.677 million of test year costs contradicts the Board's accounting of all merger related costs via the Merger Order, and would ensure the recovery of these one-time merger costs annually upon conclusion of this proceeding.

Board Discussion and Analysis

Having reviewed the record in this matter, the Board **HEREBY REJECTS** the Company's proposal to include a mechanism in rates to further address merger related savings and costs of $42,696,000 to achieve those savings, because the treatment of merger related costs and savings have already been addressed by this Board in its Order in the Merger Proceeding. Specifically, the Board's Merger Order acknowledged that the Company sponsored a merger synergy study that estimated merger synergy savings over the period 2001 –2011 would approach $1.6 billion net of approximately $335 million in costs to achieve those savings. Further, the Stipulation adopted by the

JCP&L contends that costs such as Project Evolution were not included in the Merger Order's list of specific merger costs that it was prohibited from using to reduce merger savings. It further asserts that Project Evolution costs were incurred to enable the merger savings to be realized, and should be recognized in determining the incremental net test year merger savings to be carried forward in rates.

RPA

The RPA argues that FirstEnergy's decision to implement a SAP system was a merger-related business decision. Costs associated with the Project Evolution portion of SAP should be deemed merger-related and no additional cost recognition or rate recovery of Project Evolution is necessary or justified. The RPA recommends a total annual SAP amortization expense of $5,800,000, based upon an expense reduction of $1,697,000 related to Project Evolution.

Staff

Staff agrees with the RPA with respect to its proposed SAP adjustment. FirstEnergy was not using the SAP system at the time of the merger and Project Evolution came out as an updated, integrated approach to integrate the FirstEnergy and GPU accounting systems.

Board Discussion and Analysis

For those reasons set forth in the Merger cost section of this Order, the Board **HEREBY REJECTS** the Company's proposal to include in rates those costs related to Project Evolution amounting to $1,697,000 in annual amortization expense. We concur with the positions expressed by Staff and the Ratepayer Advocate that these costs should be deemed as merger related costs and no additional recognition or rate recovery is warranted as the treatment of merger related costs have already been addressed in the Merger proceeding Order. The Company acknowledged that these costs relate to First Energy's decision to implement a SAP system for its own companies, a system First Energy was not using at the time of the merger but determined should be used to integrate the First Energy accounting system with the GPU accounting system. Accordingly, the Board **HEREBY ADOPTS** a total annual SAP amortization expense of $5,800,000 based upon an expense reduction of $1,697,000 related to Project Evolution.

N. Rate Case/Regulatory Expenses

JCP&L

JCP&L proposes to increase Pro Forma Operating Expenses by $783,000 for rate case expenses, based on a three-year amortization of $2,348,000, which it estimates will be incurred for legal fees and expenses, consultant fees and expenses, court reporter fees, public notices and postage, and messenger services associated with the instant proceeding. The proposed adjustment sets a normalized level of expenses, given the restructured regulatory environment.

JCP&L asserts that the estimated rate case expenses should be updated to the greatest extent possible, but notes that there will always be some estimated expenses because legal fees and other expenses continue to be incurred after the end of the test year. JCP&L argues that the Board has traditionally recognized that a certain "normal" level of rate cases expenses should be included in base rates and that a three-year amortization of rate case expenses is appropriate because such proceedings will continue to be required in the post-restructuring era.

JCP&L disagrees with the RPA's proposal to recognize only 50% of the rate case expenses of this proceeding. While acknowledging the Board's policy of a 50/50 sharing of rate case expenses between ratepayers and shareholders, it argues that the regulatory world has changed since its last rate case. JCP&L also notes that the initiative to file the instant proceeding was not theirs but rather that the Final Restructuring Order directed JCP&L to file the instant case. The Company argues that the Board should factor this consideration into its determination of whether to require a sharing of rate case expenses in this proceeding.

RPA

The RPA recommends: (1) that JCP&L's estimated rate case expenses be reduced from $2,348,000 to $2,000,000 until the actual amount becomes known; (2) a 50/50 sharing of rate case expenses, and (3) a five-year amortization of rate case expenses.

The RPA argues that the precise amount that JCP&L will spend on this proceeding will not be known for some time and that it is possible that the actual expenses will be significantly less than the estimated amount. The RPA notes the Board's policy allowing above-the-line treatment of only 50% of a major utility's rate case expenses. The RPA also contends that a three-year amortization of rate case expenses is unreasonably short because JCP&L's last base rate case was over ten years ago.

Staff

Staff agrees that rate case expenses continue to be incurred after the end of a test year. Staff recommends that the Board direct JCP&L to submit a revised estimate of its rate case expenses when it files its Exceptions to the Initial Decision. The Staff believes that this will allow the Board to make its determination using expense data that is current and accurate.

Staff recognizes that JCP&L was directed by the Board to file this proceeding; nevertheless, Staff sees no reason to deviate from the Board's long-standing policy of a 50/50 sharing of rate case expenses. While a rate case benefits the ratepayers through the continuation of safe, adequate and proper utility service, it also benefits shareholders, because the Company has a renewed opportunity to earn a fair return on equity. Staff recommends that JCP&L's rate case expenses be amortized over four years. Based on Staff's recommendations the Company will see a net income adjustment of $290,000 to its test year Pro Forma Operating Income.

Board Discussion and Analysis

Based upon the record in this matter, the Board **HEREBY FINDS** projected total rate case expenses of $2,348,000 to be reasonable. Consistent with the amortization period

applied to other expense items in this matter, the Board **HEREBY ADOPTS** a four-year amortization period, as recommended by Staff, to be a reasonable provision for the Company to recover this level of rate case expenses. Further, the Board **HEREBY FINDS** that the circumstances in this matter do not warrant a deviation from long-standing Board policy to share rate case expenses on a 50/50 basis between ratepayers and shareholders. The Board concludes that an annual rate case expense of $294,000, as recommended by Staff, is appropriate for inclusion in rates in this proceeding.

O. Production-Related Regulatory Asset Amortizations

JCP&L

JCP&L proposes an increase of $4,892,000 to its test year amortization expense level of $1,049,000, by revising the amortization of five of its production-related regulatory assets which it has divested. The Board previously approved these regulatory assets for recovery using various amortization periods. Instead of utilizing these amortization periods, JCP&L proposes to use the assets' remaining balance as of December 31, 2002, and to amortize this balance over a four-year period, consistent with the restructuring transition period. This adjustment also includes an amortization of the Department of Energy Enrichment Facility test year fees over a four and one-half year period, consistent with the remaining DOE assessment period. This adjustment would transfer these fees from BGS to base rates, which JCP&L asserts is more appropriate, consistent with other production-related regulatory assets.

RPA

The RPA notes that none of the assets proposed to be amortized will be decommissioned until at least 2009, and that to accelerate the amortization for these regulatory assets without re-examining other issues simultaneously decided by the Board in its Restructuring Orders would upset the "delicate balance" struck by the Board in those cases. Accordingly, the amortization period originally approved for each asset should remain in effect until the remaining balances are recovered.

The RPA does not object to including DOE Enrichment Fees in base rates, provided that they are removed from base rates in approximately 2008 when the four and one-half year amortization period expires.

The RPA's recommendation to recognize the existing amortization level of $1,049,000 related to production-related regulatory assets, plus $2,288,000 related to the DOE enrichment fees, results in a total proposed amortization expense of $3,337,000, in comparison to the $5,941,000 expense sought by JCP&L, for a total expense adjustment of $2,604,000, thus increasing net income by $1,540, 000.

Staff

Staff concurs with the RPA that it would be inappropriate to accelerate amortization for the regulatory assets without simultaneously re-examining other elements of the Board's Restructuring Orders. Staff also agrees with JCP&L and the RPA regarding the transfer of DOE Enrichment Fees from BGS to base rates.

Board Discussion and Analysis

The Board **HEREBY FINDS**, consistent with the positions of Staff and the RPA, an alteration of the amortization of these assets as proposed by the Company is inappropriate. The Board agrees that without re-evaluating the issues previously decided by the Board in the prior proceedings where these amortization periods were approved, the delicate balance struck between the competing interests of ratepayers and shareholders might be upset. The Board **FURTHER FINDS**, consistent with the recommendations of the RPA, Staff and the Company, that the Department of Energy Enrichment Fees should be transferred from Basis Generation Service to base rates and amortized over the four and one-half year amortization period as proposed by the Company. Accordingly, the Board **HEREBY ADOPTS** an amortization expense of $3,337,000.

P. Restructuring Transition Costs

JCP&L

JCP&L proposes to include certain amortizations in its Pro Forma Operating Expenses associated with certain restructuring related costs which were approved by the Board in its Final Restructuring Order. The proposed adjustment increases JCP&L's Pro Forma Operating Expenses by $8,813,000 and represents a proposed eight-year amortization of a total of $70,500,000 in expenses, which includes $62,900,000 for Voluntary Enhanced Retirement Program Cost, $3,200,000 for Bridged Retirement Benefits and $4,400,000 for Voluntary and Involuntary Severance Payments.

JCP&L argues that the Board's Final Report and EDECA provide for rate recognition of certain restructuring related costs and that the Board approved the recovery of such costs over an eight-year period in its Final Restructuring Order. JCP&L notes that there was no regulatory proceeding in progress when these costs were written off, and argues that while accounting rules required them to be written off under those circumstances, that does not mean they should not be recovered in rates.

RPA

The RPA asserts that JCP&L's proposed amortization is for work-force reductions that occurred in 1996, two years prior to the enactment of the EDECA. The RPA asserts that EDECA was not intended to permit the retroactive resurrection of costs that were written off before it became law. The RPA argues that JCP&L's request is not an appropriate accounting or ratemaking practice and that JCP&L should have petitioned the Board in 1996 for permission to defer the charges.

Staff

Staff notes that the Board began its review of the future structure of the

Staff believes that both the Board and the Legislature intended that New Jersey's electric utilities recover through their respective rates reasonably incurred restructuring related employee separation costs, including the costs of severance pay. Accordingly, Staff recommends allowing JCP&L $8,813,000 in test year operating expenses for the amortization of employee related restructuring transition costs.

Board Discussion and Analysis

Based upon events, as noted by Staff, pertaining to the time period of the Board's review of the future structure of the energy industry, the Board's issuance of the Green Book, the Board's March 7, 2001 Order referenced by the Company above, and the findings of the Legislature with respect to restructuring related costs, the Board **HEREBY ADOPTS** the Company's proposal to include $8,813,000 in test year operating expenses. This represents an eight-year amortization period of the Company's restructuring transition costs of $70.5 million.

Q. Incentive Compensation Expense

JCP&L

JCP&L has several employee incentive plans, encompassing its management, professional, administrative and bargaining unit employees. Each plan includes Key Performance Indicators ("KPIs") that correspond to the performance objectives for each employee group. The KPIs vary from one employee group to another, but commonly include key measures related to productivity, cost reduction, and customer satisfaction. The Company asserts that its plans are significantly weighted toward operational measures rather than financial measures, since operational measures focus on its customers' main concerns.

The Company argues that incentive compensation is a necessary component for any organization, if that organization is to attract and retain talented and capable employees. The Company notes that since its last base rate case, there is an upward trend of companies offering incentive compensation plans for their employees. The Company further argues that: (1) tying pay to performance can reduce costs and improve productivity; (2) incentive compensation is a tool that allows employers to focus employee efforts on specific goals and to reward higher performance; (3) competitive pressures, brought on by deregulation, have created a significant role for incentive compensation in utilities; and (4) incentive plans align the interests of all stakeholders, including the Company's employees, shareholders, and its customers.

The Company contends that unions have become much more accepting of incentive pay plans and that JCP&L's incentive plans covering union employees include specific operational measures that have been specifically negotiated between the union and management.

The Company believes that it would be a step backward if the Board rejected all or part of the Company's proposal to include incentive pay in its test year operating expenses. The Company believes that base pay alone does not recognize performance, is not tied to the wants or needs of its customers, and could lead to a decline in its employees' job performance.

RPA

The Advocate recommends excluding Incentive Compensation Expense of $4,818,000, from JCP&L's test year operating expenses. The Ratepayer Advocate disagrees with JCP&L's argument that the Company's customers benefit from all of the incentive compensation plans. According to the RPA, the stated objectives of certain incentive compensation plans place shareholder gain as the primary goal of each plan. The Advocate believes that since FirstEnergy's shareholders are the intended primary beneficiaries of those incentive compensation plans, FirstEnergy's shareholders should bear the cost responsibility for those incentive pay plans. The Ratepayer Advocate did not object to the inclusion of the remaining incentive compensation related to payments for operational goals to certain union regional goals, meter readers and customer service representatives.

Staff

The Staff notes that the in two prior decisions, the Board considered the issue of incentive compensation for ratemaking purposes. I/M/O Jersey Central Power and Light Company, BPU Docket No. 91121820J (June 15, 1993), ("1993 JCP&L proceeding"); and I/M/O the Petition of Middlesex Water Company, BPU Docket No. WR00060362 (June 6, 2001), ("Middlesex"). In those decisions, the Board expressed its belief that incentive compensation expenses should not be included in the expenses allowed for recovery by a utility in the rates charged to its customers. The Staff believes that the underlying reasoning supporting the Board's rejection of incentive compensation in the 1993 JCP&L and Middlesex proceedings remains valid today and continues to provide a basis supporting the disallowance of the amount requested by the Company for its Incentive Compensation Expenses, where the stated objectives of the incentive compensation plans place shareholder gain as a primary goal of the plan. Staff also noted that JCP&L now has several incentive compensation plans and that these incentive compensation plans are made available to a significantly wider array of employees that at the time of the Board's 1993 JCP&L Order. Staff concurred with the recommendation of the Ratepayer Advocate to include incentive compensation related to payments for operational goals to certain union regional goals, meter readers and customer service representatives. Accordingly, Staff concurred with the recommendation of the Ratepayer Advocate that $4,818,000 in incentive compensation expenses be excluded from JCP&L's test year operating expenses.

Board Discussion and Analysis

In accordance with long-standing Board policy on the issue of management incentive compensation, the Board **HEREBY FINDS** the recommendations of the Ratepayer Advocate and Staff to disallow $4,818,000 of the Company's total incentive compensation expenses to be reasonable for two reasons. First, as was the case at the time of the Board's findings in JCP&L's 1993 Order, today's economic conditions also do not justify passing the cost of incentive compensation through to ratepayers for programs that primarily benefit shareholders, especially when it is evident that many ratepayers, homeowners, and businesses alike, are having difficulty paying their utility bills or otherwise remaining profitable. Secondly, the treatment recommended by the Staff and the Ratepayer Advocate is fair and reasonable given that it recognizes that incentive compensation plans have been made available to a wider array of employees since was the case in 1993 and such plans cover union employees and include specific

operational measures that have been specifically negotiated between the union and management.

R. Miscellaneous Expenses

JCP&L

JCP&L asserts that it eliminated institutional, goodwill, and image advertising from its test year expense consistent with the Board's policy regarding advertising expenses. JCP&L argues that the subject advertising expenses were informational in nature and related to a customer education campaign to inform customers about the reintroduction of the JCP&L name. JCP&L avers that the nature of the advertising for which it seeks recovery is not mere image building, but related to community affairs and public relations activities that are encouraged or required by the Board. JCP&L asserts that it is important for customers to know who to call in emergency situations or to how to obtain information about its services and programs and argues that this type of informational advertising is clearly appropriate for rate recovery.

RPA

The RPA proposes to exclude costs associated with community affairs, public relations, and image advertising from JCP&L's test year operating expenses. The RPA believes that JCP&L's ratepayers should not be required to pay JCP&L for its commitment to meets its customer service obligations. The RPA asserts that excluding public relations and image advertising from a utility's revenue requirement is consistent with Board policy. The RPA proposes to exclude $167,000 for public relations expenditures, $605,000 for image building expenditures, and $186,000 in "other" expenditures from test year operating income, producing a total $958,000 reduction to test year operating expenses and a $567,000 increase to test year operating income.

Staff

Staff reviewed samples of JCP&L's bill inserts, print ads, and radio scripts and based upon its review, notes that the Company's bill inserts were designed to inform customers about rates, the number to call in case of a power outage, safety guidelines, how to read an electric meter, conserving energy and/or water, low income programs such as Lifeline, and other essential information. Accordingly, Staff agrees that the costs associated with bill inserts meet the Board's guidelines for informational advertising and should be included in test year operating expenses.

However, the print advertisements and radio scripts associated with the reintroduction of the JCP&L name and the Company's renewed commitment to reliability and customer service are, in Staff's opinion, clearly designed to enhance the goodwill, credibility, reputation, character or image of the Company, and thus fit the Board's definition of institutional advertising, and should be excluded from test year operating expenses. This results in a $605,000 reduction to test year operating expenses.

Consistent with its recommendation regarding the JCP&L's proposal to reclassify contributions to charitable organization from income deductions to operating expenses, Staff further recommends that the expenses associated with the American Red Cross, the Freedom House Foundation, the New Jersey Conference of Mayors, the New Jersey

Builders Association, the Northeast Sustainable Energy Association, and for individual memberships be excluded from test year operating expenses. This results in a $186,000 reduction to test year operating expenses.

Staff noted that actual test year operating expenses include $167,000 for public relations and community affairs expenses. While the above-described items are designed in part to inform the public about regulatory matters, public safety and energy conservation, these items are also designed to enhance JCP&L's image. JCP&L did not provide a separate breakdown of the individual expense items. Therefore, the Staff recommends disallowing the entire $167,000 for Community Affairs and Public Relations expenses from JCP&L's operating expenses.

Board Discussion and Analysis

In the past, the Board has held that expenses associated with informational advertising should be reflected in rates and that the expenses associated with institutional and/or promotional advertising should be disallowed for ratemaking purposes. The Company testified that the subject advertising expenses were informational in nature because they related to a customer education campaign to inform customers about the reintroduction of the JCP&L name and to emphasize the Company's commitment to reliable service. The Board **HEREBY FINDS** that ratepayers should not be required to pay JCP&L to publicize its commitment to meets its customer service obligations. Moreover, based upon a review of the samples of JCP&L bill inserts, print ads and radio scripts, the Board **FURTHER FINDS** that these were primarily designed to enhance the goodwill, credibility, reputation, character or image of the Company or increase the demand for utility service and are not eligible for recovery in base rates. Therefore, the Board **HEREBY FINDS** that $958,000 should be disallowed from JCP&L's miscellaneous expenses as recommended by the RPA.

S. Interest Synchronization

JCP&L

JCP&L proposes an adjustment to synchronize that portion of its Federal Income Tax expense associated with rate base and the weighted cost of debt utilized to support rate base. It includes the Weighted Cost of Monthly Income Preferred Securities ("MIPS") in its proposed adjustment, asserting that this is consistent with prior Board Orders.

JCP&L disputes the RPA's use of a different capital structure from that proposed by JCP&L. It argues that the RPA's capital structure includes a level and assumed cost on non-existent debt that distorts JCP&L's actual existing level of debt and related interest expense, creating an interest synchronization that is misleading and inaccurate.

RPA

The RPA proposes to modify JCP&L's adjustment to reflect its recommended level of rate base and the weighted cost of debt. The weighted cost of debt component in the RPA's interest synchronization proposal does not include MIPS.

Staff

Staff agrees with the Company's methodology. Staff included MIPS in the weighted cost of debt component of its interest synchronization calculation because MIPS is a form of long-term debt and the intent of an interest synchronization adjustment is to synchronize the Federal Income Tax expense associated with rate base and the weighted cost of debt utilized to support rate base. Staff's interest synchronization adjustment results in a total adjustment to test year interest expenses of $15,565,000 and a $6,358,000 increase to Pro Forma Operating Income.

[redacted]

The Board **HEREBY FINDS** the Staff's position on interest synchronization to be consistent with the Board's policy to synchronize interest expense in the Federal Income Tax expense calculation by applying the weighted cost of debt to support rate base, including MIPS, to that rate base. The Board **FURTHER FINDS** that the Staff position has been modified to reflect the Board's other findings herein. The Board **HEREBY ADOPTS** $80,482,000 as an appropriate interest expense for the purposes of interest synchronization.

[redacted]

consideration of post test year adjustments. Accordingly, the Board **HEREBY ADOPTS** the Staff and the Ratepayer Advocate's position on this issue.

U. BPU & RPA Assessments Adjustment

JCP&L

JCP&L proposes an adjustment reflecting the normalization of the BPU's and RPA's assessments based upon normalized test year revenues and estimated assessment rates in the amount of $848,000. It proposes to allocate this adjustment by allowing $287,000 for the RPA assessment and $561,000 for the BPU assessment. JCP&L argues that the RPA failed to use the latest known assessment rates.

RPA

In its 12+0 updates, the RPA used the assessment rates that applied to payments made by JCP&L in 2002. This 12+0 adjustment reflects a total $22,000 adjustment to BPU and RPA assessments or a negative net $13,000 income tax adjustment. Specifically, the resulting BPU pro forma assessment is $3,705,000 compared to $3,687,000 as proposed by the Company and a RPA pro forma assessment of $926,000 as compared the Company's filed $922,000.

Staff

Staff supports the RPA's 12 + 0 adjustment because it (1) accounts for the growth in the level of customers; (2) utilizes the most recent assessment rates, and (3) includes a tax adjustment.

Board Discussion and Analysis

The Board having reviewed the record in this proceeding **HEREBY FINDS** that for the reasons articulated by Staff regarding the BPU/RPA assessment the recommendations made by the RPA and Staff are appropriate. Accordingly, the Board **HEREBY ADOPTS** the 12+0 adjustment reflecting a $22,000 adjustment to the BPU/RPA assessments.

V. Service Reliability

JCP&L

JCP&L asserts that the service reliability issues which the RPA raises are not relevant to this rate proceeding, but rather relate to separate service reliability proceedings instituted by the Board pursuant to N.J.S.A. 48:2-25.

RPA

The RPA assessed JCP&L's reliability related policies, technical standards, performance standards and maintenance practices, such as age/loading of transformers, tree-trimming practices, and stray voltage events. The RPA asserts that JCP&L's customers have long endured severe and prolonged power outages, which on two recent occasions

resulted in formal investigations by the Board.[18] The RPA further notes that in the Merger Order, the Board conditioned its approval of the merger upon specific Board concerns with staffing levels, reliability, and customer service performance.. The RPA further notes the Board's most recent investigation of JCP&L, in I/M/O the Board's Investigation Into JCP&L's Storm-Related Outages of August 2002, BPU Docket No. EX02120950 (March 13, 2003), questioned the Company's storm response and the overall reliability of its electric distribution system.

Staff

Staff notes the Board's previous expression of serious concern regarding JCP&L's restoration performance in BPU Docket No. EX99100763 (the "Phase I Order"), dated April 28, 2000 and in BPU Docket No. EA9907485 (the "Phase II Order"), dated May 1, 2000, wherein the Board adopted reports by its consultants, Stone & Webster Management Consultants.[19] As a result of several investigations since 1997, the Board ordered JCP&L to implement corrective measures to mitigate the impact of storm related outages and improve overall service reliability to address some of the issues raised by the RPA. These included a Circuit Action Plan, a Recloser Program, installation of a Supervisory Control and Data Acquisition ("SCADA") system, substation transformer testing and maintenance practices, and tree-trimming programs.

Staff believes that investigations similar to the Phase I and II reviews of specific events and periodic management audits focusing on reliability issues, including those issues raised by the RPA, are reasonable approaches to address reliability concerns, which should assist JCP&L in improving its level of reliability. Staff recommends that the issues raised by the RPA should continue to be addressed in other reliability-related proceedings currently or prospectively before the Board.

Board Discussion and Analysis

The Board has long had a concern with reliability in JCP&L's service territory. The Board has conducted and is currently conducting reviews and focused audits related to service problems. There have been a number of outages in recent summers, most notably in 1999 in Red Bank. I/M/O the Proposal to Perform a Review and Investigation

The Board itself has taken several measures to increase service quality and reliability in JCP&L's service territory. For instance, an investigation is being performed on JCP&L's storm response in August 2002, I/M/O Jersey Central Power and Light Company Storm Restoration Effort for the August 2, 2002 Outages, in Docket. No. EX02120950 dated March 13, 2003.[20]

By Order dated July 16, 2003 in Docket. No. EX03070503, this Board directed the Company to take immediate action to address the problems it experienced during the 2003 summer. In addition, as a result of the outage problems experienced over the July 4, 2003 weekend by JCP&L customers in the shore areas, the Board is reviewing an expedited action plan, including the appointment of a Special Reliability Master to oversee necessary reliability improvements in an expedited manner.[21]

The Board further believes, however, that, as part of its decision in this case, it is appropriate that additional measures be taken to improve JCP&L's system-wide reliability, as discussed below.

1. **Measurement and Analysis of JCP&L Reliability Performance**

The Board **HEREBY FINDS** that both the arguments of the RPA and Staff are persuasive, in light of documented events adversely affecting the Company's customers. The Board further **FINDS** merit in Staff's recommendation that reliability and service quality issues should be addressed in other reliability-related proceedings currently or prospectively before the Board. The Board therefore **HEREBY ORDERS** that a Phase II proceeding ("Phase II Proceeding") be conducted to review whether the Company is in compliance with current service reliability and quality standards set forth in N.J.A.C. 14:5-7 and to address whether additional performance standards are required for JCP&L, such as specified targets to improve JCP&L's reliability and service quality in the shore area, on both a short-term and long term basis, as well as to improve service quality and reliability throughout JCP&L's entire service territory. Such improvements must be undertaken immediately by the Company in the most expedited and efficient manner. It is anticipated that the results of the current ongoing reviews and focused audits, including the review of the Special Reliability Master, will be considered in the Phase II Proceeding.

The Board further **APPROVES** Staff's recommendation that the Company be ordered to segregate on its books all capital expenditures related to improvements of its system. Any such expenditures and projects undertaken by JCP&L to increase its system's reliability will be reviewed as part of the Phase II proceeding, to determine their prudency and reasonableness for rate recovery.

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[20] On September 24, 2003, the Board hired Booth & Associates to perform an investigation of the Company's overall system reliability and to recommend specific areas for improvement.

[21] On August 1, 2003, the Board retained the Special Reliability Master to investigate the events leading to the July 2003 outages and to make recommendations to mitigate such occurrences in the future.

2. Service Quality Index

JCP&L

In its reply brief, the Company responds to the proposal by RPA to subject JCP&L to a Service Quality Index requiring the Company to maintain certain levels of service quality and reliability. The Company believes that the reliability issues raised by the RPA do not and should not be considered as part of the pending base rate proceeding. The Company argues that the Board has not adopted the service and reliability standards proposed by the RPA. JCP&L maintains its belief and recommendation, which the Company asserts is supported by Staff, that the standards and mechanisms embodied in the RPA's proposals should be considered within a comprehensive process developed under the Board's auspices and rulemaking authority.

RPA

The RPA, through its witness Barbara Alexander, proposes that JCP&L be subject to a Service Quality Index that requires the Company to maintain historical levels of service quality and reliability and imposes financial penalties in the form of rebates to customers for the failure to maintain these performance standards on an annual basis. The performance standards would not only apply to duration and frequency of outages, but also to such areas as call centers, residential customer installation of service, and customer complaint ratio.

In 2000, the BPU adopted Interim Electric Distribution Service Reliability and Quality Standards, codified at N.J.A.C. 14:5-7 (effective January 2, 2001). These Standards establish a minimum service reliability level for each electric utility consistent with the recommendations of the Reliability Working Group established by the Board. The Reliability Working Group consists of representatives of the electric utilities, the RPA and Staff. The Reliability Working Group reviews the current reliability standards and reports to the Board on recommendations for further action.

Ms. Alexander further testified that in late 2002, the Board stated that it intends to adopt permanent standards with penalties for noncompliance that would be applied automatically. However, the Board has not initiated any proceeding to implement this proposal. Ms. Alexander noted that until these permanent standards are established, there are no automatic penalties or other enforcement actions that are linked to failure to maintain the stated reliability performance levels.

Staff

Staff agrees with the RPA that there is a need to establish permanent reliability standards with penalties for noncompliance. However, Staff believes that these standards should apply to all the electric utilities at the same time and for that reason the Board had established the Reliability Working Group Process. In late 2002, this Reliability Working Group initiated the process and has conducted meetings in order to work on the interim standards and establish permanent standards. In those meetings, the four electric utilities indicated that they had either completed or were close to completing their new Outage Management System ("OMS") and it would require them

three to four years to perfect the OMS in order to collect the reliable data upon which the permanent standards could be based.

Subsequently the Reliability Working Group jointly decided that pending completion of the new OMS, there was insufficient data that could be relied upon in order to make meaningful permanent standards, and that the utilities would collect OMS data until year 2005 before the Reliability Working Group recommends permanent reliability standards.

Staff believes that these permanent standards should have other customer service metrics such as timeliness of installation of service, call center performance, accuracy and customer complaint performance. Staff recommends that any reporting requirements, benchmarks or performance standards on these metrics should be established at the same time the permanent standards are developed in 2005.

Board Discussion and Analysis

The Board **FINDS** that the establishment of a service quality index, as proposed by the RPA and supported by Staff, to tie financial penalties to levels of service quality and reliability, is not appropriate at this time. However, the Board **FINDS** that Staff's recommendation regarding the establishment of industry-wide permanent standards for measuring service quality and reliability should be initiated as early as practicable. The Board therefore **DIRECTS** Staff to reconvene the Reliability Working Group to review the Board's existing Interim Electric Distribution Service Reliability and Quality Standards, N.J.A.C. 14:5-7, and to recommend any modifications relating to the establishment of such permanent standards. Also, the Board will review the results of the Booth audit, and the Report of the Special Reliability Master which may result in specific performance criteria to assure improvements in reliability throughout JCP&L's service territory..

W. COST OF SERVICE / RATE DESIGN

1. Cost of Service

JCP&L

JCP&L's Cost of Service Study ("COSS") follows the traditional process of functionalization, classification, and allocation of costs to rate classes based on [illegible]

accounts 364 through 368. JCP&L used a voltage specific average and excess allocation method to allocate the transmission and distribution plant cost to rate classes.

JCP&L asserts that it constructed its COSS using the same general methodology and traditional principles as were used in prior studies accepted by the BPU in previous proceedings, wherein the Board recognized that there is both a demand and energy component associated with transmission and distribution system costs, and adopted the voltage level specific average and excess methodology for the classification and allocation of transmission and distribution costs ("Average and Excess method).[22]

The Company performed certain [redacted]

The RPA argues against using a single non-coincident demand allocator even if the distribution system is sized to meet JCP&L's claimed single maximum peak. The RPA believes that if sizing provided the only basis for allocation, then all costs associated with load-bearing equipment would be allocated on the basis of demand. The RPA contends that in JCP&L's last base rate proceeding, the Board rejected the exclusive use of demand based allocation methods for transmission and distribution

Staff argues that by utilizing ratios which separate distribution plant into primary and secondary subfunctions that are different than previously used and approved by the Board, JCP&L over-allocated $54,351,277 in costs to rate class RS and $5,815,813 to rate class RT, while under-allocating costs of approximately $30,000,000 to rate class GS, $23,000,000 to rate class GST, and $7,000,000 to rate class GP.

Staff also criticizes the Company's 12+0 updates for not adhering to the Board's approved cost of service methodology. Staff recommends that JCP&L undertake a new cost of service study that fully complies with the Board's pronouncement on the appropriate cost of service methodology as set out in the 1993 Order. In the absence of this information, for purposes of equity, Staff recommends that the distribution-only revenue decrease (after adjustment for the proposed increase of $4.2 million allocated to the lighting class) be distributed on an across-the-board basis to the rest of the classes.

DISCUSSION AND FINDINGS

With regard to allocating the $222.7 million base rate decrease to the various customer classes and developing the appropriate rate design, there is no disagreement that the Average and Excess Methodology (with the excess defined as each customer class's contribution toward the overall system peak) was the preferred method of the Company, Staff and the RPA. However, there was disagreement about certain aspects of the Average and Excess Methodology, all of which focused on the Company's deviation from the Board's policy on the allocation of distribution-related costs.

Absent a cost of service study that fully complies with the Board's most recent findings on the Average and Excess Methodology (with the excess defined as each customer class's contribution toward the overall system peak), Staff recommends that the distribution only revenue decrease (after adjustment for the proposed increase of $4.2 million allocated to the lighting class) be distributed on an across-the-board basis to the rest of the rate classes. The Board reiterates its full support of the Average and Excess Cost of Service Study Methodology as prescribed in JCP&L's 1992 and 1993 Orders and S-22 (which is S-50 from Dkt. ER91121820J) supported by the Board in those cases and **DIRECTS** JCP&L in its next base rate case to fully comply with those orders and submit the appropriate cost of service study.

In the interim, however, in an effort to moderate the impacts to customer classes and for this case only, the Board **HEREBY ADOPTS** the proposed allocation of $79.9 million as reflected in the Company's proposed Settlement and Staff's recommendation to allocate the additional revenue decreases of approximately $142.8 million to the different customers classes, across the board, based upon class proposed settlement distribution revenues. The reduction is apportioned based on each class's percentage of total settlement distribution revenues, excluding GTX, which receives its allocation under GT. For the Lighting Class, which under the Company's proposed Settlement position would have received a rate increase, the Board **HEREBY ORDERS** that the increase be limited to the overall percentage change to the RS Class. For the deferral proceedings, the Board **HEREBY ORDERS** that the increases or decreases be reflected on a usage basis as well as each unbundled non-bypassable charge. For the following interveners who filed specific proposals as to themselves and were signatories to the Company's proposed Settlement, the Board **HEREBY ORDERS** the following:

For Gerdau Ameristeel Sayerville, Inc., (formerly Co-Steel) the Board **HEREBY ADOPTS** the proposed Settlement provisions for Gerdau, effective upon the expiration of Co-Steel's existing contract for service on April 1, 2004. Gerdau will be served as a Service Classification GT customer, subject to all provisions and charges provided for in Service Classification GT, except that (1) the Distribution Charge shall be $1.87 per kw (exclusive of Sales and Use Tax) ("SUT") based only on the actual maximum monthly 60 minute demand for the current billing period, whether on-peak or off-peak; (2) the distribution KVAR and KWH charges shall not be applied, and (3) an MTC credit of $.009844 per kwh shall be applied to all kwh usage.

Regarding the United States Department of Defense/Other Executive Federal Agencies, the Board **HEREBY ADOPTS** the proposed Settlement provision for DOD which provides for a credit against distribution kw and kwh charges calculated to provide an overall reduction in charges to DOD customers that, in the aggregate for all such DOD customers, equals $3.367 million on an annual basis (excluding SUT), based on such customers' 2002 usage, as compared to rates in effect on January 1, 2003, after taking into account the effect of both the lower charges for Service Classification GT and such credit.

For New Jersey Transit, the Board **HEREBY ADOPTS** the proposed Settlement provision to modify GT-Commuter Rail Service Special Provisions so that weekday hours of 5:00 p.m. to 8:00 p.m. shall be considered as off-peak hours for billing purposes. The Board **FURTHER ORDERS** the inclusion of the following language in the Commuter Rail Service Special Provision in the Tariff for Service Classification GT:

> Where traction power is supplied at high voltage (230kv) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand.

The Board **APPROVES** the proposed Settlement provision to modify the demand (KW) charge component of the delivery charge to alleviate intra-class customer impact disparities for commercial and industrial customers. Moreover, service classification GST customers shall have an increase in the tariffed monthly customer charge of $11.54 and $16.47 (excluding SUT) for single-phase and three-phase, respectively. All other tariffed monthly customer charges shall remain unchanged.

2. Market Transition Charge ("MTC")

JCP&L

JCP&L proposes to alter the current basis on which its MTC rates were determined. The MTC charge, a transitional charge, was used as a residual for rate design to accommodate the requirement to maintain interclass and intraclass rate neutrality pursuant to the Board's Restructuring Orders. JCP&L proposes to remove the residual effect embedded in the MTC charge for the post-transition period. The MTC charge, as of June 2002, included the Transition Bond Charge ("TBC") and Market Transition Charge Tax ("MTC-Tax") associated with Oyster Creek related stranded costs. The MTC also includes unrecovered BGS costs. JCP&L proposes to adopt an MTC recovery mechanism consistent with the operation of the former LEAC, adjusted for customer voltage for billing purposes. Based on forecasted kWh usage for 2002, the

MTC revenues at the Company's proposed MTC factor adjusted to the voltage level of each rate class totaled $252,978,195, including 6% in Sales and Use Tax ("SUT").

RPA

The RPA opposes JCP&L's proposed MTC rate design, arguing that it substantially increases the burden on residential and general service customers. The RPA asserts that for these customers, the Company's proposal increases their respective MTC revenue responsibilities by 53% and 84%, which is well above the 41% overall MTC revenue increase. The RPA contends that the Board's Final Restructuring Order eliminated the LEAC and that, beginning August 1, 2003, the MTC will no longer recover energy related costs, recovering, instead, only stranded costs, but in a manner different from the recovery of energy costs pursuant to the former LEAC.

The RPA recommends the allocation of future MTC revenues in the same proportion as in the current MTC. The RPA proposes a flat per kWh MTC charge applicable to each rate class based on the total MTC revenues as proposed by JCP&L and its forecasted 2002 kWh usage. The resultant MTC revenue increase to the RS class would be 41% as opposed the Company's 53%, and 40% to the GS class, as opposed the Company's 84%. Hence, the RPA recommends that future MTC revenue burdens be allocated in the same proportion as current MTC responsibility. As such, based on total MTC revenues proposed by the Company and its forecasted kwh usage for 2002, the RPA would apply a flat, per kwh MTC charge applicable to each rate class. The RPA recommended MTC revenue increases for the RS and GS classes are $36,655,013 and $37,224,719, respectively.

Staff

Staff calculated the MTC revenues for each rate class using the RPA's proposed charges. Staff also calculated the RPA's proposed percentage increase/decrease to each rate class using the Company's schedules and the RPA schedules.

Staff agrees with the RPA that JCP&L's proposed LEAC-type mechanism for the recovery of MTC revenues disproportionately affects the RS and GS customer classes. Staff reasons that the MTC was created to recover the above-market cost relating to generation assets in the context of restructuring. To maintain the rate caps during the transition period, however, the Board allowed utilization of the MTC as a residual charge. Staff believes that at the end of the transition period, it will be necessary to separate the various components of the current MTC charge so that energy components will be reflected in BGS, leaving the MTC to recover stranded costs. Staff further believes that the impact of JCP&L's proposed MTC rate design must be weighed against the overall impact from the Board's approved delivery cost of service results and also viewed in the context of previous Board approved mechanisms for recovering such or similar costs and its original treatment of the MTC in the restructuring proceeding.

Board Discussion and Findings

As discussed above, Staff indicated that the impact of JCP&L's proposed MTC rate design must be weighed against the overall impact from the Board's approved delivery cost of service results and also viewed in the context of previous Board approved mechanisms for recovering such or similar costs and its original treatment of the MTC in

the restructuring proceeding. The Board in rendering this decision weighs this issue against the impacts to the individual customer classes and previous Board approved MTC rate design mechanisms for recovering such costs. The impacts in the Board's Summary Order and in this Final Order have all reflected this adjustment including the 3.5% impact to the residential class as well as the intra-class impacts resulting from this decision and included in the compliance filing dated July 28, 2003 and approved by the Staff in its September 5, 2003 letter finding the compliance filing to be in compliance with the Summary Order's terms and conditions. Moreover this mechanism is consistent with the voltage specific rate design treatment approved by the Board in its July 31, 2004 decision in the Atlantic City Electric deferral matter.[23] Thus, the Board **HEREBY APPROVES** JCP&L's voltage level adjustments to the individual class MTC charges.

3. Reconnection and Service Charges

JCP&L

JCP&L proposes to increase its reconnection charge for the restoration of service after a service disconnection requested by the customer or because the customer is in default. The current tariff provides for a reconnection charge of $22.00 to customers served under the RS, RT, RGT, GS, and GST tariffs, during normal weekday working hours. During all other times, the reconnection charge is $45.00 for RS, RT, and RGT customers, and $54.00 for GS and GST customers. JCP&L proposes a revised charge of $27.00 for service performed at the meter during normal weekday working hours, and a revised charge of $70.00 for service performed at all other hours to the above-listed service classifications. JCP&L would base all disconnection and reconnection services on actual cost for service classification GP, GSP, and GT. JCP&L also proposes to increase the RS, RT, and RGT service charge from $45.00 to $70.00 and the GS and GST charge for final bill readings performed outside of normal working hours from $54.00 to $70.00.

RPA

The RPA recommends that the current reconnection and service charges remain unchanged. The RPA argues that JCP&L's proposed increase is significantly above the average amount charged by the State's other electric utilities, and is excessive and unduly burdensome to JCP&L's low-income customers. The RPA believes that JCP&L's reconnection charges should be based solely on direct costs that have a linear relationship to the number of reconnections performed without the inclusion of overhead costs.

STAFF

Staff finds the RPA's alternative perspective on the calculation of the reconnection charge compelling and worthy of consideration. It would result however, in a reconnection charge of $16.94 during normal working hours and $44.45 during all other hours, supporting the position to maintain the existing charges. Staff agrees with

[23] I/M/O The Petition of Atlantic City Electric Company D/B/A Conectiv Power Delivery for Approval of Amendments to its Tariff to Provide for an Increase in Rates for Electric Service, BPU Docket No. ER02080510 (July 31, 2004 Summary Order).

maintaining the existing reconnection charges but also turns to recent Board policy on this issue, which consistently established reconnection charges that did not make a distinction between normal business hours and all other hours. Staff recommends that JCP&L only charge the RS, RT, and RGT customer classes a flat fee of $22 for all hours of service restoration. Staff believes that this will soften the impact to those customers who are attempting pay bills in arrears and improve their credit with the Company. Since the Company already has two separate reconnection charges for normal working and all other hours respectively, Staff recommends that the Board maintain the distinction between normal business hours and all other hours for GS and GST customers but continue the existing $54 fee during all other hours.

Staff further recommended that the existing service charges remain at their current level.

Board Discussion and Findings

With regard to Reconnection Charges and Service Charges, the Company proposes in its proposed Settlement to increase reconnection charges from $22.00 to $27.00 during normal business hours (8 a.m. to 4:30 p.m.), and from $54 to $70 at all other hours. The Board **HEREBY REJECTS** this proposal and **HEREBY ORDERS** that JCP&L maintain a flat reconnection fee of $22.00 for all hours of restoration for RS, RT, and RGT classes, and maintain the present rates for GS and GST classes of $22.00 and $54.00 during normal business hours and other hours, respectively. The Board **FURTHER ORDERS** that actual costs shall provide the basis for disconnection and reconnection services for GP and GT classes. The Board **HEREBY REJECTS** JCP&L's proposal to increase existing service charges during other than normal working hours of 8:00 a.m. to 4:30 p.m. Monday through Friday, to $70.00 for all customer classes and **HEREBY ORDERS** that the existing service charges of $54.00 for RS, RT, RGT, GS and GST be continued.

SUMMARY OF BOARD FINDINGS, BASE RATE CASE

Based upon the above, the Board **HEREBY FINDS** the Company's rate base to be $2,016,299,000, its overall allowed rate of return to be 8.38% (including a return on common equity of 9.50%), its operating income requirement to be $168,966,000 and its pro forma operating income at present rates to be $300,436,000 or $131,470,000 more than its operating income requirement. After applying the revenue factor of 1.69398x, the Company's excess revenue requirement is $222.7 million. Accordingly, the Company is **HEREBY DIRECTED** to reduce its base rates by $222.7 million.

V. DEFERRED BALANCES CASE

A. BACKGROUND

1. Sources of BGS Supply

In accordance with the Final Restructuring Order (at 104, paragraph 7), during the first three years of the transition period the Company was to obtain its BGS supply from its owned generating units prior to divestiture, power purchase agreements ("PPAs") with other utilities and non-utility generators ("NUGs"), transition power purchase agreements ("TPPAs")[24] entered into with the purchasers of its divested generating units, and, to the

[24] Sometimes referred to as "parting contracts."

limited to, spot and short-term forward purchases of energy and capacity. The Company was also authorized to employ financial instruments, i.e., hedges, as part of its supply strategy, and while noting that the use of some of these products could reduce ratepayer exposure to price spikes and volatility, the Final Restructuring Order recognized that they could be more costly than relying on the spot market. (Id.)

On October 29, 1998, the Company agreed to sell its fossil units aggregating 1,604 Mw to Sithe Energies, Inc. ("Sithe"), a New York based large independent power producer. In response to the Company's petition filed on February 16, 1999, by Order dated November 4, 1999 ("Sithe Order"),[25] the Board approved the sale, and it closed on November 24, 1999. Under the associated TPPA, the Company could purchase up to the full capacity of the sold units (but not the energy) from November 7, 1999 through May 31, 2002 at "call" rates ranging from approximately $70 per Mw-day to $120 per Mw-day (Sithe Order at 15; S-36)

On October 15, 1998, JCP&L executed an agreement to sell its 25%, 196 Mw interest in TMI-1, a 786 Mw nuclear unit owned jointly with its Pennsylvania affiliates, Pennsylvania Electric Company ("Penelec") (25%) and Metropolitan Edison Company ("Met-Ed") (50%), to AmerGen, a partnership formed by PECO Energy Company and British

On that date it began purchasing the energy and capacity from Oyster Creek at bundled prices ranging from approximately $33/Mwh to $36/Mwh for a term extending through March 31, 2003. (Oyster Creek Order at 3; S-36)

Prior to divestiture, the energy and capacity of these units was used to supply BGS, and the related costs included as part of the costs recoverable by the revenue received from supplying BGS service[28] to customers choosing not to take service from third party suppliers, as well as the revenue from sales of energy and capacity in the wholesale power market (sales for resale). In addition to fuel, other operation and maintenance ("O&M") expenses, taxes and depreciation, the Company included in BGS recoverable costs a return on its investment in the fossil units and TMI-1 calculated at the pre-tax rate of 14.64%, which it asserts was the return on which its 1996 cost of service study employed in the Board's restructuring proceedings was based. (S-49) The investment on which the return was computed was also taken from the 1996 cost of service study, and was not reduced by monthly depreciation charges during the transition period. Id

While Oyster Creek fuel, other O&M expenses and taxes were also included as part of BGS recoverable costs, the return on and of Oyster Creek investment (as well as other Oyster Creek sale-related costs) were considered stranded costs, and included as part of the costs recoverable by the MTC. (S-51) The Oyster Creek investment cost recovery was structured to mirror a 13-year securitization via an annuity calculation at 7% interest, and prior to September 2000, was based on net plant investment (gross plant less accumulated depreciation and deferred income taxes) of approximately $500 million. In September 2000 the investment was reduced to reflect additional deferred taxes estimated to result upon the unit's retirement, or to approximately $372 million. (S-51)

The balance of the Company's BGS supply during the first three years of the transition period was obtained from long-term, pre-transition PPAs with other utilities and NUGs, short-term forward purchases (bilateral and two-party purchases), and the day ahead and real time spot markets administered by the PJM Interconnection, L.L.C. ("PJM"), now an Independent System Operator ("ISO") and successor to the power pool of the same name. Of these sources, bilateral and two-party purchases were the most significant on a cost basis, comprising as they did almost 40% of the $3.1 billion total cost of BGS supply during this period, as shown in Exhibit 1 attached to this Order.

In year four of the transition period (the 12 months ended July 31, 2003), the Company's BGS supply was obtained pursuant to the statewide auction approved by the Board by its Order in Docket Nos. EX01050303 et al. dated December 11, 2001.[29]

2. The Phase I Audit Report

Generating Station Pursuant to N.J.S.A. 48:3-7, a Specific Determination Allowing the Oyster Creek Nuclear Generating Station to be an Eligible Facility Pursuant to Section 32 of the Public Utility Holding Company Act of 1935 and a Waiver of the Advertising Requirement of N.J.A.C. 14:1-5.6(b). A final Order was issued on November 21, 2003.

[28] The production cost component of BGS revenue after deducting transmission charges and the 6% New Jersey Sales and Use Tax ("SUT").

[29] Docket Nos. EX01050303, EO01100654, EO01100655, EO01100656 and EO01100657, I/M/O the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq.

As stated in the RFP, the objective of the Board-mandated audits of the deferred balances of the four electric utilities was to "provide the Board with a certified opinion as to whether the Utilities deferred balances as of July 31, 2003 are correct and include only those costs that are reasonable, prudently incurred, accurately calculated, correctly recorded and in compliance with Board Orders." (RFP issued July 29, 2002 at 3) The audits were to be performed in two phases, the first covering the first three years of the transition period (the three years ended July 31, 2002), and the second, the last year of the transition period (the year ended July 31, 2003). For utilities that had divested their generating assets, such as the Company, the audit was to include a prudency review of BGS procurement during the first three years of the transition period, and for all utilities, a review of the utility's efforts to mitigate the above-market cost of power obtained under power purchase agreements with non-utility generators. (Id. at 2-3)

The phase one report for JCP&L was issued in two parts: a *Schedule of Deferred Balances and Attachments For The Three-Year Period Ended July 31, 2002 And Independent Accountants' Report* ("Examination Report"; S-37) prepared by Mitchell & Titus, LLP ("M&T"), and an *Audit of Deferred Balances, Jersey Central Power & Light Company – Phase I* ("Phase I Audit Report"; S-38) issued jointly by M&T and Barrington-Wellesley Group, Inc. ("BWG").

As stated in the Examination Report, M&T's examination of the Company's deferred balances as of July 31, 2002 and related compliance with the Board's Orders was conducted in accordance with the attestation standards established by the American Institute of Certified Public Accountants. Other than finding that the Board's Orders did not address a return on non-nuclear production assets that should be charged against BGS revenue, and that JCP&L did not obtain Board approval for booking $41 million of such return to its deferred BGS balance, M&T stated that "the Company complied, in all material respects, with the Board Orders regarding the deferred balances for Phase 1." (S-37, transmittal letter dated January 7, 2003, page 1) Based on data provided by the Company in its August 1, 2002 deferred balance filing with the Board, the deferred balances examined by M&T aggregated $436.2 million as of July 31, 2002, and consisted of an under-recovered MTC balance of $131.1 million, an over-recovered SBC balance of $12.6 million, an under-recovered BGS balance of $290.6 million, and interest of $27.1 million. (Id., Attachment II)

In addition to providing supporting detail for the Examination Report, the Phase 1 Audit Report included a prudency review of the Company's BGS procurement as well as a review of the Company's efforts to mitigate above-market NUG costs during the first three years of the transition period. M&T's findings and recommendations with respect to the Company's BGS, NNC,[30] SBC and MTC deferrals were covered in Chapters III through VI, and the BGS prudency and NUG mitigation reviews, which were performed by BWG, in Chapters VII and VIII, respectively.

With respect to the MTC deferred balance, the Auditors noted that the Company had incurred additional Oyster Creek costs of approximately $2.5 million not yet reflected in the MTC, and that it had chosen to amortize certain other Oyster Creek costs over 125 months rather than the 132 months (11 years) stated in the Final Restructuring Order.

[30] Non-Utility Generation Charge included in the MTC.

The resultant increase in the deferral, however, was asserted to be immaterial. The Auditors also noted that a pending IRS ruling on accumulated deferred investment tax credits and excess deferred taxes will have an impact on the MTC balance. [31] (S-38 at I-4)

With respect to the BGS deferred balance, the Auditors noted that the 14.64% rate of return JCP&L used in computing the return on its generating assets recoverable by BGS revenue had been applied in the absence of a Board Order[32] specifying the rate or methodology JCP&L should use. (Id.)

In assessing the prudency of the Company's BGS procurement, the Auditors first contrasted the Company's pre- and post-restructuring supply sources. At the beginning of the transition period JCP&L's peak load was 5,180 Mw and its installed capacity was 2,685 Mw. About 31 percent of its energy requirements was supplied by nuclear generation, 10 percent by non-nuclear facilities, and the remaining 59 percent was purchased from other utilities, NUGs and PJM. (Id.)

Following the divestiture of nearly all of its fossil-fueled generating plants (1,604 Mw) and its 25% interest in the TMI-1 (196 Mw) in late 1999, followed by the divestiture of the wholly-owned 619 Mw Oyster Creek nuclear unit in August 2000, the Company retained less than 300 Mw of owned capacity, i.e., its 50% ownership, or 200 Mw, of the Yards Creek pumped storage plant, and 66 Mw of combustion turbines at the Forked River site. For the balance of its post-divestiture BGS supply the Company relied on TPPAs with the purchasers of its fossil-fueled and nuclear generating units, spot purchases from PJM, two-party and bilateral purchases, and PPAs with other utilities and NUGs. During the summers of 2001 and 2002, the TPPAs accounted for about 17% of the cost of the Company's BGS supply, PJM purchases about 15%, two-party and bilateral purchases about 50%, NUGs about 14%, and all other sources, including owned generation, about 4%. (Id. at I-5 to I-6)

While recognizing that one of the objectives of divestiture was to maximize the sale price of the Company's divested assets, the Auditors noted that the TPPAs negotiated by the Company had exposed it and its customers to market price volatility. The lack of an energy contract associated with the fossil sale was also characterized as being "naïve" in view of the unproven nature of the competitive market. Nonetheless, the Auditors observed that the TPPAs had been approved by the Board, as had the divestiture itself. (Id. at I-6)

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[31] The Sithe, TMI-1 and Oyster Creek Orders all directed the Company to file for a letter ruling request with the Internal Revenue Service ("IRS") seeking a determination as to whether accumulated investment tax credits and excess deferred income taxes associated with the Company's divested fossil and nuclear generating units should continue to be flowed through to ratepayers on the basis that ratepayers are paying for the units' stranded costs (essentially the Company's booked investment in the units less the proceeds received from their sale). On March 4, 2003, the IRS issued a proposed rulemaking to amend the federal tax code to allow such flow through ratably to cost of service in the amounts permitted under the tax code before the divested units ("deregulated generation property") ceased to be public utility property. Comments on the proposed change were due on June 2, 2003. The IRS has not as yet issued a final rule.

[32] The Auditors did note, however, that a lower rate of return had been authorized for another utility in a Board Order.

The Auditors found JCP&L's strategy for meeting its BGS procurement responsibilities "informed and reasonable," and that the organization established by GPU to perform the procurement "was appropriately staffed to meet planning, procurement and control responsibilities." Moreover, outside consultants were retained to help develop the procurement strategy, planning and management tools, risk management policies and procedures, and employee training. The development of procurement requirements was also actively overseen by GPU management. (Id. at I-6 to I-7)

The same procurement strategies in place for JCP&L were found to have been formulated and implemented for JCP&L's Pennsylvania affiliates as well, and had as their overriding objective minimizing price volatility and the variation in BGS revenue and costs. The strategies were implemented by setting "fill targets" (the amount of on-peak energy to be purchased in a given month) as much as a year in advance, and gradually filling the targets over time with forward contracts, thereby avoiding large purchases at potentially higher prices. (Id.)

The Auditors performed an in-depth analysis of JCP&L's procurement in the high cost summer months of June, July and August of 2001, as well as the months of June and July of 2002, and with the exception of the excess supply assertedly procured for the summer months of 2001, found that JCP&L generally followed its plan for selecting fill targets. As part of this review the Auditors also compared JCP&L's procurement in the summer of 2001 to the provider of last resort ("PLR") procurement of its Pennsylvania affiliates in those months, and concluded that the same methodology for determining fill targets and procurement requirements had been used. Differences between the timing and amounts of the fill targets and related procurements, and thus procurement costs in the two states, were "reasonably attributed to differences in the shopping patterns, customer mix, NUG and utility power purchase contracts and load profiles of the utilities, rather than any attempt to manage costs in Pennsylvania or shift costs from Pennsylvania to New Jersey." (Id. at I-8)

While noting that the FirstEnergy merger may have had a negative effect on the management of BGS procurement activities in the summer of 2001, the Auditors nonetheless concluded that its effect, if any, on costs was negligible. Moreover, JCP&L's retained generation was found to have been reasonably utilized during all three summer peak periods, and not selling Yards Creek, which assertedly reduced the Company's deferred BGS balance by $9 million, at the price offered by PSE&G, the plant's other co-owner, was judged reasonable. On the other hand the Company was found to have made relatively little use of financial and weather hedges that could have provided additional volume protection and potential cost savings during the summers of 2001 and 2002. (Id.)

In reviewing the Company's efforts to mitigate above-market NUG costs the Auditors found that JCP&L had complied with Board requirements as well as the EDECA requirement that it "demonstrate the full market value of the NUG contracts, which was a condition of recovery of NUG contract stranded costs." JCP&L's mitigation program during the first three years of the transition period was evaluated using a list of Preferred Practices developed by BWG, who concluded that in general, JCP&L "had maintained a reasonable and prudent program for NUG mitigation well before the transition period and committed substantial corporate resources to mitigating the costs of its NUG contracts." With respect to the restructuring of the Bayonne contract, however, the Auditors noted

that the closing date had been delayed for six months, resulting in a potential loss of savings, and proposed to review this issue, as well as Reliant Energy's offer to restructure JCP&L's NUG contracts that was rejected by the Company, in Phase II. Lastly, the Auditors found that JCP&L had been less than aggressive in mitigating the cost of its smaller NUG contracts (the Camden, Gloucester and Kenilworth PPAs). (Id. at I-9 to I-10)

As indicated above, BWG found that JCP&L had secured too much BGS supply for the summer months of 2001, and in the absence of an adequate explanation for the excess, conservatively estimated that it increased JCP&L's deferred BGS balance by $11.7 million. Should the Board seek a disallowance associated with JCP&L's asserted failure to mitigate the Camden, Gloucester and Kenilworth PPAs, the Auditors suggested reducing the deferred balance by 10 percent of the cost of the purchases under these contracts, or by $5.6 million.[33] (Id. at I-10)

B. THE ISSUES

1. BGS Deferred Balance

(a) Standard of Review

In performing its prudency review of the Company's deferred BGS balance, BWG employed this definition: "Did management make the decisions and take the actions that a reasonable individual would have, given the alternatives and information available at the time such decisions and actions were taken, consistent with legislative and other regulatory requirements?" (Phase 1 Audit Report (S-38) at II-17) This definition, which highlighted the need to judge prudency in light of the alternatives and information available at the time decisions were made, in turn was adopted by Staff and the Company. (Staff's Initial Brief ("SIB") at 123; Company's Initial Brief ("CIB") at 129). Similarly, the Advocate agreed that in evaluating whether the Company acted reasonably and prudently in obtaining its BGS supply during the transition period, its managerial conduct should be judged "in light of the circumstances, information, and options in existence at the time management decisions were made." (RPA's Initial Brief, Vol. 2 ("RIB2") at 2). Citing the Board's Order in the Hope Creek case,[34] the RPA additionally asserted that the burden of proof as to prudency lay with the Company, and accordingly that it must show why its BGS costs were incurred and demonstrate the benefits that were derived from them. (Id. at 2-3) The Advocate additionally urged the Board to review whether the Company had mitigated risk sufficiently. (Id. at 2-3) Interveners Gerdau, DOD and NJ Transit did not address prudency in their Briefs.

(b) Prudency of the Company's BGS Procurement

JCP&L

[33] Corrected to $5.7 million at the hearing on April 28, 3003. (13T 29-2 to 7; Exhibit S-40)

[34] I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Rates and I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Rates – Hope Creek Proceeding, Docket No. ER85121163, Order dated April 6, 1987. At issue were the costs incurred in constructing PSE&G's Hope Creek nuclear plant.

During the period from August 1, 1999 through October 31, 2001, the Company's BGS procurement strategy and costs were supported by Charles A. Mascari, then Vice President – Technical Services for GPU Energy ("GPUE"), the trade name under which JCP&L and its affiliates conducted business prior to the November 7, 2001 merger of their parent company, GPU Inc., with FirstEnergy Corp. of Akron, Ohio ("FirstEnergy merger"). In addition to making supply decisions, the Power Services Division under the direction of Mr. Mascari implemented and administered a voluntary load reduction program with participating commercial and industrial customers, as well as a residential air conditioning and water heating load reduction program. (JC-14 at 8) Following the FirstEnergy merger, the Company's BGS procurement was supported by Dean W. Stathis, JCP&L's Manager of Commodity Sourcing.

Witness Mascari testified that the Company's procurement strategy was based on establishing supply targets related to each future month's forecasted peak load, or more precisely, the "MW equivalent of a percentage of the forecasted BGS load at the time of the PJM monthly peak." (Id. at 7-19 to 7-20) The target was then met by purchasing forward contracts[35] to cover the portion of the target not obtainable from the Company's committed supply (retained generation, TPPAs, pre-transition utility and NUG PPAs), with the difference between the target and the peak load made up by purchases in the PJM spot market. (Id. at 9 to 13)

Based on historical customer usage patterns, the Company developed projected monthly peak loads under assumed normal, mild and severe weather conditions. Also taken into account were trends in customer shopping experienced in Pennsylvania and other states that implemented retail competition prior to New Jersey. With the added input of forward market price volatility, the monthly supply percentages were determined using various mathematical models that "minimize[d] the difference between projected MEC [market energy and capacity] revenues and BGS costs for the range of expected customer usage and market price volatility under the mild, normal and severe weather scenarios." (Id. at 8-13 to 8-23)

On the further assumption that forward and spot market prices would be the same under normal weather conditions, the supply targets varied with changes in the other variables (the mild and severe weather assumptions), and thus the target selected was the one at which the difference in MEC revenues and costs was minimal for both scenarios.[36] (Id. at 9) As Mr. Mascari put it, "JCP&L's objective was to minimize the potential variation in the difference between MEC revenues and BGS costs given the large uncertainties associated with the spot market prices and BGS peak load requirements that were tied to weather variations, especially during the summer and winter." (Id. at 9-1 to 10-5)

Once the targets were established for the remaining months of the current and following year, the Company acquired the supply needed to meet the targets in the forward markets gradually over time, much like the dollar cost averaging ("DCA") employed with stock market purchases, in order to avoid unduly impacting the market in any one month and potentially putting upward pressure on prices. Relying on forward contracts, however, reflecting as they did a risk premium for firm future delivery and prices that

[35] And to a limited extent by the purchase of financial instruments, as shown in Exhibit 1 attached.

[36] Choosing the supply target as the point at which the mild and severe weather curves intersected, as illustrated in Schedule CAM-5 attached to JC-14, was referred to as the "X Method" or model.

could be substantially above the energy and capacity component of the shopping credit, ran the risk of incurring BGS costs well in excess of the cost of spot market purchases should the weather turn out to be mild in the delivery month. While recognizing that "[b]uying forward electric energy contracts was a risk management tool that did not and could not guarantee that spot prices for electric energy would not be lower," the Company nonetheless believed that "leaving JCP&L's customers fully exposed to potentially high electric spot prices, especially during hot summer weather, was an unacceptable and imprudent risk." (Id. at 12-16 to 13-7)

Complicating the procurement problem was the evolving nature of PJM, as it transitioned in April 1997 and April 1998 from an essentially cost-based power pool in which energy prices rarely exceeded $150 per Mwh to a bid-based, two-settlement system, the "day-ahead" market, in which purchases and sales are transacted at fixed prices based on loads and supplies forecast for that day on the previous day, and the "real time" market, in which the forecast versus actual load and supply variances are balanced, and in which prices could go as high as PJM's bid cap of $1,000 per Mwh. (Id. at 14 to 15) Similarly, the market for forward products took time to develop from its initial offering of "5x16 on peak monthly strips," which provided a constant amount of power each hour, 5 weekdays a week, 16 on peak hours a day (7 a.m. to 11 p.m. except holidays), to more diverse energy products ("shaped" products, i.e., products tailored to fit the load profile of the buyer) that could be purchased for periods longer or shorter than one month. Id. PJM's capacity auction market also experienced pronounced volatility as it developed, due at least in part to the high penalties imposed on shortages (double the capacity deficiency rate of $170 per Mw-day when the pool as a whole was short). Lastly, customer shopping did not occur at anywhere near the rate anticipated, peaking at less than 10% of load in April 2000, and, at 7 Mw, constituting about a tenth of a percent of the Company's peak load of 5,266 Mw as of October 2001. (Id. at 14-3 to 23-15; Schedule CAM-4) In concluding his direct testimony, witness Mascari asserted that the Company had "employed prudent strategies to mitigate the cost of purchased power to serve BGS customers, at the time these decisions were made, and in light of the then prevailing market conditions." (Id. at 23-7 to 23-10)

Following the FirstEnergy merger, as directed by the Board in its October 9, 2001 Order in Docket No. EM00110870 approving the merger, JCP&L established a separate organization to procure BGS supply, the Commodity Sourcing Department headed by Company witness Dean W. Stathis. (JC-15 at 4) While the basic objective of the procurement strategy remained unchanged ("minimization of the potential variation in the differences between BGS revenues and costs, given uncertainties in weather, energy market prices and their impacts on BGS load") (Id. at 4-20 to 5-5), the method of filling the supply targets changed from dollar cost averaging to an approach that allowed relatively more forward purchasing if market prices appeared attractive relative to historical norms. (Id. at 15; 4-22 to 5-20) Witness Stathis also noted that prices in the forward market began to decline in February 2001, bottomed out in February 2002, and began to firm again after that. The more flexible post-merger approach of "lock and load," as it was called, was accordingly intended to take advantage of such price declines, and beginning in November 2001, the Company accelerated its forward purchases. (Id. at 9 to11) In contrast, the pre-merger period was generally characterized by rising forward prices. Based on the procurement strategy discussed in his Direct Testimony, witness Stathis averred that the Company's post-merger BGS costs were reasonable and prudent.

RPA

In his Direct Testimony filed on December 20, 2002, the Ratepayer Advocate's witness Paul Chernick was sharply critical of the Company's BGS procurement performance, asserting that the Company "had not demonstrated that it exercised the level of care appropriate for a procurement process of the size of the BGS supply. The Company has not provided any comparison of its expenditures to any measure of market prices, a basic step in demonstrating that it performed well in this important task." (R-59 at 5-8 to 5-12) As discussed more fully in the section, *Pennsylvania vs. New Jersey Supply Costs* below, the only cost comparison then in the record, that between the prices the Company paid for its non-NUG, non-TPPA purchases as compared to the prices its Pennsylvania affiliates paid, showed that the Company paid about 13% more than they did, which translated into an increase of $239 million in the cost of its BGS supply during the first three years of the transition period. (Id. at 5-12 to 5-17; Schedule PLC-2)

The Company's alleged failure to document its decisions regarding BGS procurement in turn assertedly made it "impossible for the Board to find that JCP&L was prudent in selecting objectives, and executing the actions selected in the planning process. The lack of retrospective reports and analyses of JCP&L's decisions also directly raises questions about prudence, since frequent reports would be necessary to evaluate performance in this novel environment." (Id. at 7-2 to 7-7) Additionally, the Company's basis for determining how much energy to purchase in the forward markets was found to be flawed: rather than trying to minimize monthly variation in earnings, witness Chernick asserted, the Company should have been "attempting to minimize the cost of BGS supply for ratepayers." (Id. at 7-8 to 11)

After emphasizing how important extensive documentation of procedures, decisions and outcomes was in view of the magnitude of the Company's BGS financial commitment ("over $3 billion, comparable to the cost of a nuclear power plant"), and after outlining the detailed data he expected the Company would have routinely kept for each purchase it made, Mr. Chernick asserted that to evaluate how well the Company performed in minimizing the cost of BGS supply from a process standpoint, the Board could examine 1) whether the attributes he recommended had been included in the Company's planning and procurement process; 2) whether the Company followed its own rules and guidelines; and 3) whether its decisions were reasonable. (Id. at 11 to 16) From a results standpoint, the prices the Company paid for its BGS supply could be compared to appropriate benchmarks, including procurement by other utilities and various market indices. (Id. at 15-21 to 16-6) The Company was found wanting on all counts. (Id. at 16-25)

Mr. Chernick also critiqued the Company's models, finding, as noted above, that the objective on which they were based, minimizing the difference between BGS costs and revenues (or as it was described elsewhere by the Company, minimizing "variations in energy supply Pre-Tax Earnings due to weather") was inappropriate. (Id. at 26) Moreover, such an objective could yield the perverse result of increasing BGS costs when they were less than BGS revenues.[37] Id. He went on to discuss the so-called "X method," the spreadsheet model described in witness Mascari's Direct Testimony (JC-14 at 8-13 to 11-7) and illustrated in Schedule CAM-5 attached to that testimony. (R-59 at 26 to 27) As compared to minimizing customer costs, witness Chernick again found the

[37] Although Mr. Chernick doubted that JCP&L would intentionally increase BGS costs to bring them closer to MEC revenues, he cited that possibility to illustrate the "irrelevance of the Company's stated objective." (R-59 at 26, footnote 9)

use of this model to determine the level of forward contracts that would produce the same after-tax earnings to the Company under two arbitrarily chosen weather conditions to be misguided. Id. He also found the HOST[38] model, which replaced the X-model in February 2001, to be inadequately explained, and that the monthly "fill" rates it prescribed (5% of the target per month until the target was met two months prior to the delivery date) were in any event disregarded by the Company. (Id. at 26-17 to 28-7, including the footnote on page 27) Moreover, the targets prescribed by either model were found to have varied erratically over time, and with the advent of the accelerated purchasing strategy following the merger (the lock and load strategy), several examples of overshooting or undershooting the targets were cited, and plotted in Schedule PLC-4, in which Mr. Chernick compared the actual to the targeted fill rates for the months of December 2001 through July 2002. (Id., Schedule PLC-4) Moreover, in an apparent inconsistency, the historical norms on which the Company based its accelerated purchasing decisions turned out to be the average actual PJM on peak prices over the three-year period 1998 through 2001, rather than the forward prices asserted by the Company. (Id. at 29-8 to 29-17)

Mr. Chernick also cited several examples of the Company's failure to provide after-the-fact comparisons of its costs of purchasing BGS supply to other measures of costs, including the Company's response to a discovery request[39] in which it refused to compare the costs of its congestion hedges to the actual cost of congestion on the grounds that "an after the fact comparison such as is requested has no relevance in determining whether or not the acquisition of a hedge was an appropriate action at the time such acquisition was made." (Id. at 31) Similarly, in its response to another discovery request,[40] the Company stated that it had not analyzed whether the post-merger acceleration of its forward purchases had reduced the cost of BGS supply relative to the pre-merger strategy because it did not believe "such after-the-fact analyses were relevant because the prudence of the actions must be judged in light of the facts and circumstances as they existed at the time the decision was made and cannot be reassessed with 20/20 hindsight." (Id. at 30-23 to 31-12)

Moreover, Mr. Chernick asserted that the Company did not even retain information that would permit a before-the-fact prudency review of its purchasing decisions. (Id. at 31 to 32) In responding to yet another discovery request,[41] for example, the Company stated that it did not save the market price data it received from brokers at the time it made its purchase decisions because such data served no further "operational" purpose. (Id. at 31) Neither did the Company save the price quotes it received when it made market sales. Id. Nor did it document the capacity offers, market intelligence, notes of discussions with counterparties, or the conclusions and decisions it made based on this information. Id. Additionally, because it apparently didn't perform any after-the-fact analyses as it went along, there was no way of assessing the effectiveness of the Company's procurement decisions:

[38] The acronym for "Hedge Optimization Strategy Tool."

[39] RAR-BGS-132.

[40] RAR-BGS-127.

[41] RAR-BGS-12(a).

> It is true that the outcome of any one decision, out of many, does not determine whether it was "an appropriate action at the time such acquisition decision was made." Good decisions sometimes have bad outcomes. But JCP&L should have been conducting after-the-fact comparisons throughout the BGS procurement period to guide its procurement. Furthermore, Your Honor and the Board need to see the results of after-the-fact comparisons today.
>
> The Company should have been conducting after-the-fact comparisons throughout the BGS-procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted, or stopped entirely. I do not believe that JCP&L could prudently acquire BGS supply without such information.
>
> [Id. at 32-3 to 16]

Finally, Mr. Chernick asserted that the Company had not shown that it had managed its load control and demand-response programs in a way to minimize BGS costs.[42] (Id. at 33-3 to 33-12)

JCP&L's Rebuttal

In Rebuttal Testimony filed on January 24, 2003, Mr. Mascari disputed Mr. Chernick's assertion that the Company had not demonstrated that it had exercised the level of care appropriate for a procurement process the size of its BGS supply. As evidence, he included in his testimony a copy of a presentation the Company made to the Board's Staff and the Ratepayer Advocate in April 2000 that described the Company's procurement strategy, the processes and organization it established to implement the strategy, its Risk Management Position Tracking System, and the inputs and outputs produced to provide an audit trail of the Company's procurement actions. (JC-14 Rebuttal at 8-3 to 8-12; Schedule CAM-13) Moreover, the Company's employees and management involved in making purchasing decisions, executing transactions, or developing marketing models or otherwise involved in BGS procurement, underwent extensive training to obtain the new skills demanded by the

implemented in both Pennsylvania and New Jersey. (Id. at 9 to 11) As an example, the Company cited the Princeton Energy Programme, a classroom-based program that provided 80 hours of instruction in energy risk management and financial instruments to key employees. Teknecon Energy Risk Advisors, Inc. ("Teknecon") was also retained to assist in the development of risk control policies and procedures, and to provide guidance to the GPU Risk Oversight Committee ("ROC"), the organizational entity charged with setting and monitoring the GPU System's risk policies and procedures. Morgan Stanley Capital Group and the Brattle Group were also retained to assist in the development of hedging strategies and a "position tracking" software system. (Id. at 9-10 to 12-15)

Mr. Mascari also discussed the sources of data the Company relied upon to insure that its purchases in bilateral markets[43] were made at no more than market prices, including NYMEX, PJM and ECAR market data, Platts' Power Market Week, and real time quotes from Morgan Stanley Capital. (Id. at 14 to 17) The Company also had standing agreements in place for executing physical purchases and sales with a wide variety of firms, as well as for purchasing financial instruments. Evaluating the latter was aided by software tools @RISK and @ENERGY.[44] (Id. at 14-3 to 16-7)

Discretion and the flexibility to respond to changing circumstances, particularly in the aftermath of the California energy crises in mid-2000 and when prices began to fall in the post-merger period, were said to have accounted for the variations in fill and target rates Mr. Chernick inaccurately characterized as being "erratic." (Id. at 19-13 to 22-5)

In defending the Company's objective of minimizing variation in the difference between BGS costs and revenues, Mr. Mascari asserted that, by taking into account a wider range of uncertainties, this objective was superior to Mr. Chernick's simplistic "minimize cost" approach. (Id. at 22-6 to 23-4) In summary, in finding Mr. Chernick's concerns baseless, Mr. Mascari asserted that:

- JCP&L's divestiture of its generation assets and procurement of full output TPPAs for its nuclear plants and capacity options for its fossil plants was consistent with Board policy and reasonable assessments of its ongoing needs, and was approved by the Board.[45]

- JCP&L approached the BGS procurement process with the highest level of care, including extensive training of responsible personnel and use of expert consultants.

- JCP&L had the same incentives to control BGS costs as its Pennsylvania affiliates, because of the known risks of this prudence review, and the Company and its Pennsylvania affiliates employed the same fundamental procurement strategies, so that any differences in outcomes were the

[43] Markets not formally organized as exchanges.

[44] An additional model, Nostradamus, described by its vendors as a "short-term, neural network-based demand and price forecasting system," was also apparently used to assist in preparing short-term forecasts. (R-59 at 26-22 to 23)

[45] In his Direct Testimony (R-59), Mr. Chernick had faulted the Company for not obtaining energy as well as capacity in negotiating the TPPA for the fossil units with Sithe.

result of differences in the underlying markets and customer base in the two states.

? JCP&L's processes and procedures for BGS procurement ensured that all purchases of relevant products were effected at then-prevailing market prices for the product in question at the time of purchase.

? JCP&L has provided extensive amounts of data in this proceeding that support all aspects of its BGS procurement process.

? JCP&L's implementation of its BGS procurement processes was consistent with its strategies and plans, as the use of rigid fill formulas would not have been prudent, and any alleged deviations from the strategy have been explained by external events.

? JCP&L's objective to minimize variances and risks was appropriate.

? JCP&L has pursued an active and aggressive NUG mitigation program.

? JCP&L made appropriate use of its load-control and demand response programs to mitigate BGS costs.

[Id. at 26-1 to 27-14]

With respect to the post-merger period Mr. Stathis challenged Mr. Chernick's assertions that the Company lacked a coherent post-merger strategy and that it had not demonstrated that its load-control and demand-response programs were effectively managed to reduce BGS costs. (JC-15 Rebuttal) As to the first assertion, Mr. Stathis explained the Company's post-merger strategy as follows:

> JCP&L had in place a procurement strategy that was based upon triggering additional purchases above and beyond minimum targeted levels when forward prices dropped to the level of JCP&L's estimates of the marginal cost of production and thus were unlikely to fall much lower. This decision to accelerate short- and long-term procurements for the post-merger time period of November 2001 through June 2002 was an outgrowth of a study undertaken in the summer 2001 and dubbed the "Lock & Load" study. This research had identified PJM on-peak forward electricity price levels that were approximately equal to JCP&L's estimates of the marginal cost of producing electricity in the PJM region. When the merger closed in early November 2001, the "Lock & Load" price triggers were discussed with FirstEnergy management, who recommended implementing a price trigger range based upon three-year averages of actual average monthly on-peak prices and the "Lock & Load" values [shown in Schedule DWS-6]. JCP&L reviewed and

> accepted this Recommendation. This range was the basis for 58 on-peak forward purchases totaling 3400 MW [shown in Schedule DWS-7]. Thus, the post-Merger procurement strategy had a definite justification.
>
> [Id. at 2-2 to 2-22]

As shown in Schedule DWS-6 attached to JC-15 Rebuttal, the prices that would trigger lock and load advance purchases of on-peak energy for the target months of December 2001 through June 2002 varied from a low of $29.37 per Mwh to a high of $35.35, and with few exceptions were adhered to in making the 3,400 Mw of forward purchases shown in Schedule DWS-7.

Given that the HOST model was no longer used in setting monthly supply targets after the merger (the targets simply became the average peak load forecast for the target month), Mr. Stathis asserted that the data on which Mr. Chernick's Schedule PLC-4 was based was incorrect, and thus that this schedule did not accurately portray the variance between the actual and targeted fill rates. (Id. at 3-18 to 4-3)

In response to Mr. Chernick's assertion that the Company's load-control and demand-response programs had not been shown to have reduced BGS costs, witness Stathis pointed out that the "PowerPlus Savers Program," a water heating and air conditioning load reduction program for residential customers in which more than 74,000 customers were participating by 2002, achieved a total load reduction of 62 Mw in 2002. (Id. at 5-6) While no estimate of the cost reduction achieved by the Power Plus program was provided, Mr. Stathis estimated that the Company's Voluntary Load Reduction Program, in which 40 commercial and industrial customers participated, reduced its deferrals by $1.1 million through 2002, and its peak load by 45.5 Mw. (Id. at 5-1 to 6-16)

In refuting Mr. Chernik's assertion that minimizing the difference between BGS costs and revenues was not an appropriate objective of the Company's target-setting models, the Company also presented the testimony of Frank C. Graves, a Principal with the Brattle Group, a Massachusetts-based firm that provides consulting services to the electric power and natural gas industries. In Rebuttal Testimony filed on January 24, 2003, Mr. Graves identified the appropriate goals of a prudent supply strategy as being "1) the procurement of firm, reliable supply for the BGS net load at prices prevailing in the competitive wholesale markets, 2) the reduction of the *ex ante* (*i.e.*, before-the-fact) volatility risk of BGS procurement costs, and 3) the avoidance of exposure to transient, adverse market conditions." (JC-19 Rebuttal at 18-4 to 18-14)

Given that market prices are not within the Company's control, the goal of supply procurement becomes one of reducing volatility (risk management), which, while not materially changing expected costs, does protect against extreme outcomes. "As such, it should be judged on its ability to control variation around the expected market costs of procurement, rather than variation around BGS rates or revenues." (Id. at 19-15 to 20-6)

To illustrate his point, witness Graves presented a graph (Exhibit FCG-6 on page 6 of JC-19 Rebuttal) comparing the probability distribution of the possible costs of a strategy under which forward power to meet the supply requirement of a future delivery month is purchased gradually over time, to one that relies exclusively on spot market purchases in

that month. While the mean, or expected cost of the two strategies is assertedly the same, Mr. Graves observed that the range of potential variation is much greater for the spot market strategy. The curves also showed that while there is a higher probability of experiencing costs lower than the mean under the spot strategy, the probability of experiencing increased costs is also higher. However, due to the "skewness" of the spot market cost distribution, the amount by which the higher spot market cost is likely to exceed the mean is greater than the amount by which it is likely to be less, and accordingly this should be taken into account in deciding upon a forward purchasing strategy.

As to managing "procurement to the BGS rate itself," i.e., eliminating the deferral entirely, that is not feasible due to the fact that wholesale prices exceeded the capped BGS rate during the transition period, and thus the purpose of risk management was to ensure that the actual under-recovery did not deviate very far from the expected under-recovery. (Id. at 20-7 to 21-2; 24-19 to 25-1)

In describing the Company's models and how they evolved, Mr. Graves began with the X-Method employed by the Company until February 2001, when it was replaced by the HOST model. (Id. at 32) Using the month of July as an example, Mr. Graves showed how the difference between the Company's projected BGS costs and revenue ("Pre-Tax Earnings Equivalent") varied under mild and severe weather conditions. On the assumption that forward prices reflect normal weather conditions, purchasing increasing amount of forwards will result in reduced costs if the weather turns out to be severe, since the spot price would then be expected to be higher than the forward price. (Id. at 33) Conversely, purchasing lesser amounts of forwards will result in reduced costs if the weather turns out to be mild, because the spot price would be expected to be less than the forward price in this case. Id. The point where the upward sloping severe weather curve intersected the downward sloping mild weather curve was chosen as the supply target (the percentage of the July load that was to be supplied by forwards). As shown by the graph illustrating the method (JC-19 Rebuttal, FCG-9 on p. 33), the target for July appeared to be somewhat greater than 100%. (Id. at 32-8 to 33-15)

Turning to the Host model, witness Graves noted that while it was conceptually similar to the X-Method, it incorporated a number of enhancements, including the ability to model "more numerous and complex scenarios, more hedging instruments, greater use of market information about the relationship between forward and spot prices, correlation between load and price, and a more formal measure of risk. [46] Specifically, it expands the scenario set from two basic weather scenarios (mild and severe) to a continuous price probability distribution spanning many load conditions. In addition, it calculates an optimal hedging strategy based on the use of forwards and options (monthly over-the-counter call options for on-peak forwards) as hedging instruments, rather than just forwards." (Id. at 34-1 to 34-13)

In finding both models to be appropriate tools in managing JCP&L's BGS risk, witness Graves also found the supply targets set by their use to have been reasonable, and not to have changed arbitrarily as contended by Mr. Chernick. The single instance in which a

[46] The "certainty equivalent" of net cash flows, which was asserted to be "a well known and commonly used technique to effectively value different distributions of outcomes by placing a dollar value on the variance (based in this case on JCP&L's risk tolerance level), thereby allowing for direct dollar-to-dollar comparisons across different procurement strategies." (JC-19 Rebuttal at 30-10 to 18, including the footnote) The JCP&L reference was to its management, not its ratepayers.

substantial shift in the X-Method targets occurred, that between January 3 and January 17, 2000, Mr. Graves attributed to the realization that customer switching to third party suppliers was not going to occur to the extent previously assumed. Similarly, the declining supply targets set by the HOST model were explainable by the declining forward prices that occurred in 2001 and 2002. Finally, in countering Mr. Chernick's apparent belief that off-peak as well as on-peak hours should have been hedged, Mr. Graves cited the much greater price risk exposure associated with on-peak energy and the limited availability of off-peak forwards and options. (Id. at 35-3 to 39-11)

In concluding his testimony, Mr. Graves noted that of the approximate $3 billion of power resource costs JCP&L managed during the transition period, about $1.6 billion took the form of open market purchases, and that:

> Of this procurement, essentially none of it had controllable costs, and only some of it had controllable risks. For instance, the costs of intra-month spot balancing were essentially unhedgeable, as were the costs of PJM charges such as ancillary services. The total amount of BGS load that had to be served was initially highly uncertain, because of the unfulfilled expectation that there would be a significant shift toward retail suppliers. But even without that occurring, the market-procured component was a volatile, complex, peaky, weather-sensitive residual shape that was ill-suited to being covered by standard, relatively flat wholesale contracts. The PJM market itself was in a state of developmental flux, including some occasional doubts about the quality of its competition, to which JCP&L was particularly vulnerable.
>
> In this extremely complex environment – far more difficult to evaluate than most mature commodity markets such as currencies or interest rates that are usually deemed quite complex – JCP&L developed a series of sophisticated models that it monitored and updated regularly. While relying on those models for formal measures of risk, JCP&L also exercised a great deal of careful but difficult out-of-model judgment about the quality of market performance it was facing. Under the circumstances, I think this is successful, prudent decision-making that should not involve any disallowances.
>
> [Id. at 40-1 to 41-3]

Auditors' Findings

In reviewing the prudency of the Company's BGS procurement, the Auditors found that the Company "had not provided an adequate explanation for deviating from its BGS fill strategy and exceeding hedge target procurement levels for the summer of 2001 during the months of January through March of 2001." (Phase 1 Audit Report (S-38) at I-10; VII-36) Based on an analysis of the Company's forward procurement for the months of June, July and

August 2001 (Id. at VII-37 to VII-42), and the quantification shown in Exhibits VII-20, 21 and 22 and explained on pages VII-57 through VII-59, the Auditors recommended that the Company's BGS deferred balance be reduced by $11.7 million to eliminate these "excess and unnecessary costs." (Id. at VII-36) While the Auditors performed a similar analysis of the Company's forward purchases for the months of July and August 2002, they proposed no disallowance for these months. (Id. at VII-43 to VII-44)

Staff's Position

Staff agreed with witness Chernick's criticism of the models employed by the Company, as well as his contention that they were inconsistently applied in securing BGS supply during the first three years of the transition period. In particular, Staff found the objective that drove both the X-Method and HOST models, minimizing the difference between BGS costs and revenues, i.e., minimizing the effect on the Company's earnings, to have been misguided and inappropriate. While such an objective may have had some justification in obtaining the provider of last resort supply for the Company's affiliates in Pennsylvania, it clearly had none in New Jersey, where if anything, the Company realized an earnings *benefit* from its deferred balances by virtue of what, in retrospect, was a generous carrying cost allowance, the yield on 7-year constant maturity treasury notes plus 60 basis points, on the deferred balances during the transition period.

While noting that if costs were less than revenues, minimizing their difference could actually increase BGS costs, Mr. Chernick did not suggest that this result actually occurred. However, Staff was less sanguine, asserting that one could not be certain that this objective of the Company's models (the HOST model in particular[47]) could not, or did not produce this perverse result. Nor in Staff's judgment was this issue ever satisfactorily addressed by the Company.

Moreover, this choice of the models' objective appeared to Staff to permit outright speculation, or purchasing energy in excess of the Company's requirements. Given that under normal circumstances energy costs per kwh will always be higher than the annual average in the peak summer months (July and August, typically),[48] the only possible way the difference between BGS revenue from sales priced at the fixed annual average (the shopping credit) and the costs incurred in these months could be minimized is through buying forward contracts in excess of load,[49] and re-selling the excess energy at a profit – an extremely risky strategy in Staff's view, in that it exposes the utility to potentially

[47] As indicated in Attachment RAR-BGS-48(3) included in Exhibit R-56, the inner workings of the HOST model are so abstruse as to have made it impractical, if not impossible to tell in this proceeding if, how, or under what circumstances this result could occur.

[48] This is attributable to the economics of supplying load that varies seasonally, i.e., low capital cost, high fuel cost generating units (single-cycle CTs) are installed for the express purpose of economically serving seasonal (peak) demand.

[49] See, for example, the graph on page 12 of Attachment RAR-BGS-211(5) included in Exhibit R-51, which indicates that the hedge target that minimized the variance in the total cost of BGS supply in the delivery month of July 2000 was 124% of gross load (load not reduced by committed supply). On a net basis after deducting committed supply, the target was 151%, as indicated on page 15 of Attachment RAR-BGS-211(5). While the graph portrays the variance in cost, under the assumption of fixed BGS revenue, minimizing the variance in cost would also presumably minimize the variance in the difference between the revenue and the costs.

large losses if the excess energy has to be resold at a loss.[50] Moreover, this appears to have been exactly what happened in the months of June and July 2000.

In a series of presentations the Brattle Group made to GPUE in the fall of 2000 in support of its recommended dollar cost averaging,[51] and while the purpose of the presentations was to compare the recommended DCA approach to the Company's BGS procurement strategy in use at that time, the Brattle Group did, in fact, perform a retrospective analysis of how JCP&L's actual BGS procurement results compared to both the DCA approach and 100% reliance on the PJM spot market during the period from December 1999 through July 2000. As shown on page 7 of the November 29, 2000 presentation (and repeated on page 31), under the Brattle Group's proposed DCA hedging method, the *ex-post* (after-the-fact) cost of on-peak energy purchased during the 8 month [redacted]

Given the sheer magnitude of the difference, Staff maintained that a reasonable person would have concluded that under its procurement method, the Company was both purchasing more forward energy than it needed and paying far too much for it, and thus should have examined less costly alternatives at that time (the fall of 2000), about half-way through the first three years of the transition period when a change in the Company's procurement method could have made a meaningful difference in the costs incurred during the balance of the period.

As to the first issue, purchasing too much energy, setting hedge targets simply defines how much energy is to be contracted for in advance, and how much is to be obtained from the spot market. Given the unpredictability of estimating what the future cost of energy might be,[53] one simple alternative to the Company's approach cited by Staff as an example would be to, at most, be only "half wrong" by purchasing 50% of the delivery month's uncommitted supply forward, subject to a price constraint, and relying on the spot market for the other half. By limiting forward purchases to 50% of the supply requirement, speculative purchases (purchases in excess of the energy needed) would be eliminated.

As to the second issue, paying too much, Staff pointed out that the Company had a long history of purchasing very large quantities of interchange energy from PJM, and thus had to have known that what it was paying for forward energy was far in excess of the cost of its historical purchases. Rather than paying any price in a market that was much more illiquid than the PJM spot market, Staff asserted that the Company should have established a threshold for the forward risk premium above historical cost beyond which it would not go (5%, for example),[54] and place correspondingly greater reliance on the spot market, i.e., for up to all of its requirements if forward prices exceeded the threshold, again on the basis that the Company was unlikely to do any worse than if it had contracted for the forward purchases at prices greater than the threshold.[55]

While noting that more sophisticated alternative procurement methods could undoubtedly have been examined, Staff's point was that in the face of what Staff considered to be clear evidence that the Company was on the wrong track as early as September 2000,[56] it and its consultants nevertheless chose not to explore potentially better alternatives, but also committed further to a flawed and inappropriate purchasing strategy by adopting the simplistic and only modestly effective enhancement of dollar

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[53] For all the reasons outlined above by the Company.

[54] As compared to an average premium of approximately 23% estimated for the transition period by comparing the average forward on-peak price ($46.76 per Mwh) calculated from Mr. Graves' Revised Exhibit FCG-8, to the average on-peak spot price calculated from that exhibit ($37.95 per Mwh). One possible explanation suggested by Staff for this high premium is that in addition to the time-related component, it reflects at least some allowance for severe (hotter than normal) weather, contrary to the Company's assumption of normal weather.

[55] Staff considered the "lock and load" strategy to be *de facto*, albeit belated, recognition on the Company's part that a purchasing strategy linked to historical cost was the better way to go.

[56] The month in which the first Brattle Group presentation that contained the retrospective analysis discussed above was made.

cost averaging. Staff found that to have been clearly imprudent, and recommended that $152.5 million of the Company's deferred BGS balance be disallowed.

In quantifying its recommended disallowance, Staff compared the cost of the Company's "discretionary purchases" (defined below) to the substantially lower cost of purchasing the same energy and capacity from PJM. Credited against this difference were cost benefits achieved from the Company's TPPAs, also as compared to purchasing the same energy and capacity from PJM, as well as savings achieved from renegotiating the PPA with the Bayonne NUG project. While based on data supplied by the Company, this analysis was similar to the "benchmark" analysis included in the Phase 1 Audit Report at Staff's request (Appendix B).

As indicated by Mr. Laros of Barrington Wellesley at the hearing on April 28, 2003, one of the uses of retrospective analyses of the type Staff requested is the quantification of the impact of a finding of imprudence. (13T 80-5 to 80-10)[57] However, rather than relying on Appendix B for this purpose, Staff used the more detailed data (the data on capacity purchases as well as energy purchases) included in Exhibit S-32, the Company's response to a discovery request[58] in which the Company was requested to perform the same analysis shown in Appendix B of the Audit Report. In both instances the data was supplied by the Company, and while there are slight differences between the two, they are not significant, as indicated below:

TABLE 1

JERSEY CENTRAL POWER & LIGHT COMPANY

Actual Cost of Non-TPPA Discretionary Purchases * as Compared to the Cost if Purchased from PJM, 3 Years Ended July 31, 2002
Appendix B of the Audit Report vs. Exhibit S-32
($ Millions)

	Gwh Purchased	Actual Cost	PJM Cost	Increased Cost, Actual over PJM $ Millions	%
Appendix B	18,711	$1,119	$793	$326	41.1%
Exhibit S-32 **	18,735	1,125	796	329	41.3%

* purchases other than those made under TPPAs and pre-transition PPAs with other utilities and NUGs, i.e., the combination of two-party, bilateral and PJM purchases made by the Company in carrying out its BGS procurement strategy.

** priced at the weighted average PJM "sink bus" LMP and capacity market rates.

[57] Subject to possible adjustment to reflect the factors discussed on the preceding page of the transcript.

[58] S-JBGS-1

Similarly, on a unit cost basis there is no significant difference between the two analyses (about $60 per Mwh for the actual purchases as compared to $42 per Mwh if the same energy and capacity had been purchased from PJM). Thus both analyses show that if the Company had relied on the default option of PJM for all of its non-TPPA discretionary purchases during the first three years of the transition period, its BGS procurement costs would have been approximately $330 million lower.

On the other hand, the Company did much better in negotiating its TPPAs with AmerGen for the post-sale purchase of the energy and capacity of TMI-1 and Oyster Creek. As shown and derived in Exhibit 2 attached, Staff estimated that during the first three years of the transition period, the Oyster Creek TPPA purchases reduced the Company's BGS procurement costs by about $64.2 million as compared to equivalent purchases of energy and capacity from PJM, and that the TMI-1 TPPA purchases reduced the Company's BGS costs by an additional $46.0 million. On a unit cost basis, the average cost of Oyster Creek TPPA purchases, at $35.29 per Mwh, was about 16% less than the estimated $41.90 per Mwh average price of PJM energy and capacity that would otherwise have been paid for the equivalent PJM purchases during the portion of the term of the Oyster Creek TPPA that fell within the first three years of the transition period (August 8, 2001 through July 31, 2002). The reduction estimated for the TMI-1 TPPA purchases is even greater: $27.52 per Mwh, as compared to $41.86 for purchasing the equivalent PJM energy and capacity over the term of the TMI-1 TPPA (December 20, 1999 through December 31, 2001), a reduction of over 34%. Moreover, in addition to the favorable pricing, the relatively long terms of the TPPAs (two years for the TMI-1 TPPA and 2 years plus an additional 8 months for the Oyster Creek TPPA, during which Staff estimates the Company realized an additional $28.1 million of savings) were clearly beneficial.

Based on the Company's projections, there will also be annual benefits from the "Deal Strike Price Adjustment" component of the TMI-1 TPPA[59] through the year 2010, of which the Company estimates its 25% share will be $12.8 million on an NPV basis. (S-53)

As indicated in Exhibit 2, Staff performed a similar analysis to assess the cost-effectiveness of the capacity-only Sithe TPPA, but found that the related capacity purchases were about $28 million more expensive than purchasing the same capacity from PJM over the period the Sithe TPPA was in effect (November 7, 1999 through May 31, 2002). However, in its Order approving the fossil sale and the Sithe TPPA, the Board found these capacity charges to be reasonable, and authorized their recovery via the Company's charges for BGS:

> These prices [the Sithe TPPA capacity prices] are in a range consistent with the capacity prices used in the determination of the average shopping credit approved for the Company by the Board [in the Summary Order]. As a result, these capacity prices that are specified in the TPPA

[59] A copy of which was provided in response to RAR-BGS-17.

> are in the best interest of the Company's customers since they will help insulate the Company from price spikes that may occur from time-to-time as it serves basic generation customers, and which otherwise could ultimately be passed on to customers. Accordingly the Board **HEREBY FINDS** that the TPPA entered into by the Company with Sithe to be in the public interest, in accordance with

[redacted]

> costs resulting therefrom to be reasonable and prudently incurred by the Company throughout the full term of the TPPA... and we **HEREBY PERMIT** the Company to flow through and/or full and timely recover the costs resulting therefrom as part of its Basic Generation Service.
>
> [Sithe Order at 15 (footnote omitted)]

Additionally, as the Company contended, by not including an energy provision in the Sithe TPPA, the Company attempted to get the highest price for its fossil assets, thereby minimizing stranded costs in accordance with Board policy. [60]

In quantifying its disallowance Staff found that the TPPA savings, as well as the savings achieved from restructuring the PPA with the Bayonne NUG project, were fairly and appropriately deductible from its imprudence quantification associated with the discretionary purchases. As summarized in Exhibit 2 attached to this Order, they totaled $176.5 million, and after deducting this amount from Staff's estimated $329.0 million of excessive costs incurred in making the non-TPPA discretionary purchases, Staff recommended a net disallowance of BGS deferred costs of $152.5 million.

In rebutting the Appendix B quantification (which as noted above was provided by the Company and is essentially identical to the quantification shown in Exhibit S-32), the Company's witness Mascari contended that not only did the use of the historical PJM prices not "reflect what would have occurred if different weather patterns and other

PJM spot prices. In actuality, however, Staff believed that the Company would have in fact purchased the same energy and capacity, only this time in the much more liquid and competitive PJM markets,[61] thereby avoiding, as a minimum, the demonstrably excessive risk premiums demanded for forward purchase commitments.

Nor did Staff find convincing the Company's argument that PJM's credit policy[62] would have limited the Company's ability to purchase replacement power from PJM, in view of the Company's creditworthiness (as evidenced by its A bond rating), past history of large interchange purchases, and importantly, the Board's Restructuring Order allowing the deferral of under-recovered BGS costs with interest and attendant assurance of recovery to the extent such costs were prudently incurred.

In contesting Staff's recommended BGS disallowance in its Reply Brief,[63] the Company again took issue with comparing its performance to the PJM benchmark, the starting point of Staff's disallowance, which the Company characterized as being hindsight-based, after-the-fact and in conflict with Staff's acceptance of the Auditors' definition of prudence. Moreover, a world in which the Company and its Pennsylvania affiliates purchased all of their requirements from PJM instead of pursuing the hedging strategy they actually followed was, to quote the Auditors, "a world that did not exist." (CRB at 79-80) Again quoting the Auditors, in the world that did exist, the Company maintained that large spot purchases by it and its affiliates would have had a substantial impact:

> JCP&L was not a major participant in the spot market other than to make up the difference between the fill and what it needed at the time, so that the spot market itself was relatively thin and shallow and had very – had low prices because only the marginal players were in it at that juncture...And to show a comparison with that market without JCP&L in it or GPU in it is not a real comparison for what the market might have looked like, had JCP&L not had a hedge strategy and been an active player in the spot market those prices would have been different...the market would have been different.
>
> [CRB at 80, citing 13T 79:13 to 80:4]

In contrast to this assertedly uncontroverted view, the Company characterized Staff's suggestion that PJM spot prices might actually have *decreased* in the absence of JCP&L's hedging as being speculative and unsupported by record evidence. Moreover,

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[61] With respect to the liquidity of a market, Company witness Graves agreed that the number of buyers and sellers present in the market "matters a lot" (8T 73-16), and as compared to the approximate 235 PJM members, that there were "probably fifty" brokers from whom JCP&L could have purchased its BGS supply, and even fewer parties willing to enter into negotiated private contracts. (8T 72-21 to 73-11.)

[62] Which, as indicated in the discussion on pages 6 and 7 of JC-14 Supplemental Rebuttal, appears to have been triggered by the default of utility.com, a small retail provider.

[63] As noted above, Staff's recommended BGS disallowance was based on the data in Exhibit S-32, which while providing more detailed capacity costs, did not otherwise differ significantly from the data on which Appendix B of the Audit Report is based.

this possibility was assertedly contrary to the testimony of every witness who addressed this issue: the Company's witness Mascari, who testified that spot prices would have increased as a result of the increased JCP&L demand, and witnesses Graves and Chernick, who averred that the market at least would have been different than it actually was. (Id. at 81) Company witness Graves additionally alluded to the potential for market power manipulation in the spot market, which he maintained was more amenable than the forward markets to such manipulation due to so-called "scarcity bidding," or the "opportunity to withhold supply and raise the price with opportunistic bidders." (Id.)

In addition to increased demand, the Company asserted that if other factors, such as weather, gas prices and the like, none of which can be known in advance, had turned out differently, spot prices would have been different than those actually realized. Before the fact, there was even the possibility that prices "could skyrocket, as they did during the disastrous California experience in 2000-2001." That in turn, the Company maintained, "was precipitated in large part by the regulatory mandate that the California utilities purchase essentially all of their requirements on spot markets." (Id. at 82, including footnote 33) The Company also cited on-peak, real-time prices experienced in PJM in July 1999 of over 15 cents per kwh, and averred that the Company most certainly would have been excoriated if these, or spot prices comparable to those experienced in California had occurred, and it had not hedged its BGS obligation. (Id.)

The Company also cited an apparent inconsistency between the cost of JCP&L's discretionary purchases calculated by Staff in Atlantic Electric's deferred balance proceeding[64] and the cost on which Staff's recommended disallowance in this proceeding is based. In its Atlantic brief (at 40), in comparing the much higher cost of Atlantic's discretionary purchases to JCP&L's and RECO's, Staff indicated that the average cost of JCP&L's discretionary purchases was $49.68 per Mwh, as compared to $60 per Mwh in this proceeding (SIB at 160), with no explanation for the difference.[65] (Id. at 83, including footnote 35) Moreover, the Company maintained that by supporting the Advocate's adjustments in the Atlantic proceeding, the basis for which, at least in part, was Atlantic's failure to enter into long-term purchased power contracts or hedging agreements to protect against excessive price spikes, Staff took an "almost diametrically opposite position" to the "results-oriented" position taken here. (Id. at 82-83) The Company also maintained that Staff summarily dismissed, without supporting record evidence, the Company's assertion that PJM's evolving credit policies would likely have precluded the Company from purchasing the quantities of power required under Staff's default option of purchasing all of its requirements from PJM. (Id. at 83-84)

As for Staff's assertion that the Company's model appeared to allow "speculative" forward purchases, the Company, citing Webster's definition of speculation ("the assumption of unusual business risk...in hope of gain; *esp.*: to buy or sell in expectation

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[64] I/M/O the Petition of Atlantic City Electric Company, d/b/a Conectiv Power Delivery for Approval of Amendments to its Tariff to Provide for an Increase in Rates for Electric Service, Docket No. ER02080510.

[65] This apparent inconsistency was also cited by the Company in its August 29, 2003 Motion for Reconsideration (at 16, footnote 10). As explained in greater detail below, the apparent inconsistency results from including JCP&L's TPPAs in Staff's Atlantic comparison and excluding them (treating them separately) in Staff's JCP&L analysis.

of profiting from market fluctuations."),[66] asserted that under the Final Restructuring Order it was not permitted to realize a profit on any aspect of its BGS activities, and thus there was no incentive for it to engage in such speculation. As for Staff's suggestion that the Company's models could establish targets in excess of load, while conceding that this could be true if the targets are compared to the average peak load (the average of all 16 peak hours on all non-holiday weekdays during a given month), the Company asserted that this was not the case if the targets are compared to the forecasted hourly peak demand for the delivery month. Moreover, that was the peak load to which its model (the X-method, in this instance) was keyed. However, "neither the Company's targets, nor its ultimate 'advance' commitments (in the form of forward contracts and pre-existing committed supply, such as NUGs and owned generation) exceeded the forecasted, normal-weather peak load." (Id. at 87-88)

The Company also contended that Staff's suggested use of historical cost as a benchmark for assessing the reasonableness of the cost of the Company's forward purchases was not relevant, because such a benchmark ignored the fundamental fact that during the Company's long history of purchasing energy from PJM, generating units were dispatched on the basis of variable operating costs in contrast to the post-restructuring market-based system now in place, under which generator owners can bid whatever they want to up to PJM's $1,000 per Mwh bid cap. (Id. at 93) Additionally, the "lock and load" strategy was not adopted in *de facto* recognition that basing purchasing decisions on historical cost was a "better way to go," as suggested by Staff, but rather to establish a "floor" that if approached, would trigger accelerated forward purchasing on the assumption that forward prices were not likely to go any lower.

With respect to the Company's failure to adequately document its purchasing decisions by not saving the price quotes it received other than the quotes it accepted, as alleged by the Advocate and Staff, the Company responded by stating that many of the quotes were voice quotes for which no formal record was kept, and in any event that retaining "mounds of irrelevant data about price quotes" was not needed in light of the Company's procedures, which assertedly insured that purchases were made at prevailing market prices. Moreover, the Auditors shared this view, asserting as they did "that in a prudence review one does not need a piece of paper for every finding and conclusion (13T 39:4-5), so long as one is comfortable with the organization, policies, procedures, methodologies, etc., being applied (13T 40:1-3)." (Id. at 95, as quoted by the Company)

The Company also re-iterated the propriety of the fundamental objective of its procurement policy ("to minimize the difference between BGS revenues and costs over a wide range of possible outcomes, i.e., to reduce the volatility risk"), and again cited the Auditors' findings in support of this objective (at VII-25 to VII-26 of the Audit Report).

While standing by its position that the higher cost of BGS procurement in New Jersey as compared to the PLR procurement costs of the Company's Pennsylvania affiliates is the appropriate benchmark for calculating the BGS disallowance, in its Reply Brief the

[66] In the context of Staff's discussion of the appropriateness of the objective of the Company's BGS procurement model, by "speculative purchases" Staff meant forward energy purchased in excess of the amount needed on the expectation of re-selling the excess at a profit (for more than its cost) in order to reduce the seasonal (summer) cost of power in excess of the annual average. (SIB at 147-148; 150) Contrary to the Company's assertion, Staff did not suggest that the Company's models *required* speculative purchases – only that they appeared to allow them. (Id. at 147)

Advocate asserted that Staff's analysis nonetheless reinforced the Advocate's position that the Company did not incur its BGS costs prudently. (RIB2 at 79) More generally, Staff's analysis was consistent with the Advocate's position that the Company should have been making after-the-fact performance comparisons all along, as asserted by the Advocate's witness Chernick:

> The Company should have been conducting after-the-fact comparisons through the BGS-procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted, or stopped entirely. I do not believe that JCP&L could prudently acquire BGS supply without such information.
>
> [Id., quoting R-59 at 32-10 to 16]

Moreover, as asserted in its Initial Brief (at 35-39), the Advocate maintained that the Company's failure to develop an after-the-fact benchmark against which its performance could be measured ignored the advice of its own consultant, Mr. Graves of the Brattle Group. The Company in turn disputed this contention, asserting that Mr. Graves agreed that the establishment of such a benchmark would be acceptable only if it were agreed to in advance by the Company and the Board. (CRB at 97)

(c) Pennsylvania vs. New Jersey Supply Costs

As indicated above, the Ratepayer Advocate recommends that the Board disallow recovery of the $239 million difference between the actual cost of the Company's non-NUG and TPPA purchases and what the cost of these purchases would have been during the first three years of the transition period if they had been priced at the comparable prices paid by the Company's Pennsylvania affiliates, Met-Ed and Penelec. (RIB2 at 23; R-59 at 7-1 to 7-14)

Mr. Chernick, the Advocate's witness on this issue, asserted that this differential may have resulted from differing incentives in the two states, in that unlike JCP&L, Met-Ed and Penelec were fully at risk for their BGS costs (PLR costs as they were known in Pennsylvania) in excess of the level allowed in rates, at least until June 2001 when the Pennsylvania Public Utilities Commission ("PaPUC") authorized their deferral through the year 2010, after which any amounts still unrecovered would have to be written off. [67] JCP&L on the other hand knew from the start that its excess BGS costs were deferrable. Moreover, their recovery was not subject to a firm termination date. (R-59 at 7-25 to 8-12)

[67] By Order issued on June 20, 2001, the PaPUC approved a settlement that, *inter alia*, permitted Met-Ed and Penelec to defer the difference between their charges to retail customers for PLR service and their actual cost of supply beginning January 1, 2001 and continuing through year-end 2005. On appeal on February 21, 2002, the

Mr. Chernick noted that in its response to discovery request RAR-BGS-6,[68] the Company argued that the average cost per kwh of its BGS purchases exceeded those of its Pennsylvania affiliates because 1) its peak requirements were higher; 2) its NUG costs were higher; 3) its level of customer shopping was significantly lower; 4) it was affected significantly more by congestion costs; and 5) because its load response to extremely hot weather tended to be higher due to the greater penetration of air conditioning in its service territory. (Id. at 9)

Mr. Chernick found these arguments unpersuasive. While agreeing that JCP&L's load factor is lower than those of the Pennsylvania companies, and that JCP&L may face higher congestion costs than they do, the Company did not quantify the effect of either of these differences. As to the other factors, he asserted that NUG costs were not relevant to the comparison, that higher shopping levels in Pennsylvania would tend to draw off higher load factor customers leaving a peakier and therefore more expensive to serve residual load, and that the cost differentials between the two states were not driven by summer air conditioning load because the differentials tended to be more pronounced in the fall and winter months. (Id. at 9 to 10)

In responding to witness Chernick's suggestion that there may have been a greater incentive to control costs in Pennsylvania than in New Jersey, Mr. Mascari emphasized that the same methods, policies and procedures were consistently applied in both jurisdictions, and averred that the regulatory risk attendant upon the Board's

them more costly to hedge, and exposed the Company to a greater number and magnitude of price spikes in the summer when its weather sensitive load would also be peaking. (Id. at 9-1 to 11-17) In that power purchased to meet JCP&L's peak load is driven by summer air conditioning load in contrast to the loads of the winter peaking Pennsylvania companies, it cannot be expected to cost the same. After deducting each company's committed supply, JCP&L's residual load is even more costly to serve in view of its greater apparent volatility and lower load factor when measured this way (21% versus 44% for the Pennsylvania companies). (Id. at 7-17 to 14-15)

While the same methods and personnel were employed in securing the supply requirements of all three companies, the supply targets and outcomes could differ for each company due to differences in load shapes, weather sensitivity, spot price volatility and forward price differences. Moreover, if the hedge targets were different in the two states (which in general they were), and the realized spot prices differed as well, the resulting costs would necessarily differ despite having the same purpose and design. (Id. at 15-16 to 18-2)

The Auditors also found that the same methodology for determining fill targets and procurement requirements was employed in the two states, and cited many of the same factors noted by witnesses Mascari and Graves as the reasons for the differing prices between the two states. (S-38 at VII-48 to VII-49)

Other than Mr. Graves' comparison of the differing LMPs faced by JCP&L and its Pennsylvania affiliates, which he suggested could account for 5% to 7% of the 13% price differential, Staff noted that the effect of the other factors cited in the Company's testimony was not quantified. Staff did, however, concede that they could plausibly account for the remaining difference, and therefore asserted that its more general benchmark, the default option of purchasing from PJM, provided a better measure of assessing the effectiveness of the Company's BGS procurement.

2. MTC Deferred Balance

(a) Return on TBD Plant

In auditing the Company's BGS deferred balance incurred during the first three years of the transition period, the Auditors found that there was no Board Order authorizing the Company to use a 14.64% rate of return in calculating the return on its generation assets included as part of the costs recoverable by BGS revenue. (S-38 at I-4) When queried by the Auditors as to the authority it relied on for using this rate, the Company responded by citing another utility's Final Decision and Order permitting that utility to calculate the return on its generating assets at the rate of 13.0 %, pre-tax.[70]

In response to a discovery request, the Company further indicated that the 14.64% rate was the rate on which the 1996 cost of service study employed in its restructuring proceedings before the OAL and the Board was based. (S-49) Staff, however, noted that a "more current overall cost of capital of 9.50%" was reflected in the stipulated reduction in the Company's average distribution rate, from 3.70 cents to 3.45 cents.

[70] I/M/O Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings, Docket Nos. EO97070455, EO97070456 and EO97070457, Order dated March 30, 2001, paragraph 22 on page 92.

(Final Restructuring Order at 93) Accordingly, Staff recommended that the Board direct the Company to recalculate the return component of the revenue requirement of its generation assets (other than Oyster Creek) included in BGS recoverable costs during the transition period using the pre-tax equivalent of the 9.50% overall rate of return, consistent with the method employed by Atlantic City Electric Company,[71] including the monthly deduction of depreciation charges when computing the return. The Advocate recommended that the ALJ and the Board "disallow the Company's self-authorized collection of a 14.64% return on its generation assets through BGS revenues." (RRB at 81).

(b) Above-Market NUG Costs and Mitigation

To the extent the cost of the Company's NUG purchases, priced at market, are not recovered from its BGS revenue, the "above market" component is included in the MTC.

In his Direct Testimony the Ratepayer Advocate's witness Chernick asserted that the Company had failed to demonstrate any management of its NUG contracts to minimize NUG costs. (R-59 at 32-22 to 33-2) In rebuttal, Mr. Mascari cited the Company's continuing and previous efforts that began in the early 1990's, as evidenced by the pre-construction buyouts of the American Ref-fuel, Crown/Vista and Freehold PPAs, thereby achieving estimated ratepayer savings of $620 million on a net present value ("NPV") basis over the life of the terminated contracts. (JC-14 Rebuttal at 23-5 to 25-12) More recently, the Company negotiated pricing concessions from other project owners aggregating approximately $60 million on the same NPV basis, and received an upfront payment of $25.4 in return for negotiating revised pricing of the PPA with the Bayonne project. Id. Moreover, the Company files a quarterly report with the Board and the Advocate that provides the status of ongoing negotiations with each project owner as of the end of that quarter.[72] Id.

In its Initial Brief, the Advocate expanded upon its criticism of the Company's efforts to mitigate above-market NUG costs, maintaining that it had failed to achieve any meaningful mitigation since the issuance of the Board's Summary Restructuring Order in May 1999, as shown by the approximate $1.0 billion of such costs reflected in this proceeding. Although relatively small savings of $6.3 million were achieved from re-negotiating the operating agreements for the supply of natural gas to the Newark Box and Parlin projects, and although talks with the Bayonne project are continuing, there has been no mitigation of above-market costs associated with the other major projects, including an estimated $250 million associated with the South River Project over the three years 2000-2003, and $114 million associated with the Lakewood project over the same period. The Advocate also cited the Auditors' findings with respect to the Reliant proposal rejected by the Company, and its less than aggressive efforts to mitigate above market costs associated with the smaller projects (Camden, Gloucester and Kenilworth). Accordingly, the Advocate recommended that the Board not permit the Company to collect interest on the NUG portion of the deferred balance, which it quantified at approximately $59.5 million, thereby apportioning some responsibility for the Company's alleged failure to mitigate NUG costs to shareholders. (RIB at 27-31)

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[71] Deducting the actual weighted cost of debt and preferred equity from the overall rate of return of 9.50%, and then grossing up the residual to determine the pre-tax common equity component.

[72] As directed by the Board in the Merger Order (its October 9, 2001 Order in Docket No. EM00110870 approving the GPU/FirstEnergy merger).

In responding, the Company in its Reply Brief urged the dismissal of the Advocate's proposed interest disallowance on procedural grounds, inasmuch as it appeared for the first time in the Advocate's Brief, and additionally maintained that it was in any event unsupportable on the merits, as evidenced by the $25 million payment received from the Bayonne project in December 2002, all of which was credited to the deferred balance, and the Company's (Mr. Mascari's) testimony on the Company's NUG mitigation efforts, with which, other than their finding on the small projects, the Auditors took no issue. (CRB at 101-103)

The Auditors provided a more comprehensive review of the history and results of the Company's NUG mitigation efforts in Chapter VIII of the Phase I Audit Report (S-38). While finding that the Company's mitigation efforts had complied with the Board's filing requirements, and that the Company for the most part had maintained a reasonable and prudent program for NUG mitigation since well before the Board's *Towner* Order, at least for its larger projects, the Auditors did conclude that the Company was less than aggressive in pursuing mitigation opportunities for the Camden, Gloucester and Kenilworth projects aggregating 50 Mw of contract capacity, and accounting for approximately $48 million of total above-market NUG costs of $770 million estimated for the period 2000-2003. (Id. at VIII-9, VIII-13; Exhibit VIII-2) Should the Board find that a disallowance related to these less than aggressive efforts was warranted, the Auditors suggested quantifying the disallowance at 10% of the contract payments made to the three NUGs during the transition period, or $5.6 million.[73] The 10% was assertedly the savings target internally set by the Company for its restructuring efforts. (Id. at VIII-16) As part of the Phase II Audit the Auditors also recommended re-examining the Company's rejection of a comprehensive NUG contract restructuring proposal made by Reliant Energy, and also investigating the reason for the delay in the receipt of the Bayonne PPA restructuring payment. (Id. at VIII-15)

In Supplemental Rebuttal Testimony filed on April 21, 2003, Mr. Mascari pointed out that the 10% savings target applied only to the above-market component of the NUG contract payments, not the entire amount, and if the 8% savings percentage actually achieved in restructuring the pricing terms of the Bayonne PPA were applied to the Camden, Gloucester and Kenilworth above market contracts payments, the disallowance suggested by the Auditors would be reduced to $2.4 million. (JC-14 Supplemental Rebuttal at 18-3 to 19-17)

Moreover, Mr. Mascari asserted that the Company had appropriately prioritized its NUG mitigation efforts in view of the uniqueness of the Camden and Gloucester projects, both of which are resource recovery facilities either owned, financed or subject to approvals by governmental entities (including the New Jersey Department of Environmental Protection) that complicate the negotiation process. (Id. at 20 to 21) The electric output of the Kenilworth project, a 15 Mw qualifying facility, has been limited to 5 Mw due to increased steam host demand, and would therefore yield minimal savings from a contract renegotiation. Id.

Staff found the Company's arguments for not accepting the suggested disallowance proposed by the Auditors convincing. With respect to the delay in the closing of the Bayonne PPA restructuring and the Company's rejection of the Reliant proposal,

[73] Corrected to $5.7 million at the hearing on April 28, 2003. (13T 29-2 to 7; Exhibit S-40)

however, Staff agreed that both should be investigated further in Phase II of the audit. Staff also noted that in addition to mitigating NUG costs through buyouts or buydowns of the related PPAs, the Final Restructuring Order directed the Company to maximize the value of NUG contract power either through market sales, or by devoting it to BGS supply:

> GPU [JCP&L] has an ongoing obligation to take all reasonable measures to mitigate the stranded costs associated with NUG utility Purchase Power Agreements, including optimizing the market revenues received for the sale of power and other marketable services derived from the Purchase Power Agreements on the open market, or for use of Non-Utility Generator and Utility Purchase Power Agreement power to offset purchases of energy and capacity or other services otherwise necessary to serve Basic Generation Service customers...
>
> [Final Restructuring Order at 109, paragraph 22]

In view of this requirement, and the possibility that using NUG energy to supply BGS could provide greater value than reselling the NUG energy to PJM,[74] and to monitor and assess the value received from the resale of the NUG energy on an ongoing basis, Staff recommended that in addition to the quarterly reporting requirement previously ordered by the Board, that the Company be directed to file monthly reports that show, for each NUG project, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (i.e., whether it was resold in the wholesale market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rate, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction.

3. Auditors' Report

JCP&L

While asserting that the Phase I Audit Report supported the overall reasonableness and prudence of its BGS procurement, the Company contested the cost disallowances recommended in the report and several of its other recommendations. Citing Exhibits S-41 and S-42, the Company noted that the report was the work of 16 professionals, including six CPAs and specialists in management, finance, engineering and operations, as well as consultants experienced in power supply procurement and NUG contract renegotiations who collectively devoted over 2,500 hours to the audit at a cost of more than $450,000. The Company summarized the report's findings as follows:

? JCP&L's strategy for meeting its BGS procurement responsibilities was informed and reasonable.

[74] Staff also cited this [redacted]

- The organization established to perform JCP&L's BGS procurement function was structured in a logical manner.
- GPU appropriately supplemented its expertise through the use of external consultants.
- GPU senior management took an active role in overseeing the development of BGS procurement requirements.
- GPU developed a reasonable strategic framework for meeting BGS procurement needs.
- The use of a methodology that attempts to minimize BGS procurement costs over a range of possible outcomes was consistent with Board requirements and was reasonable.
- GPU's BGS supply procurement practices appropriately evolved over time.
- GPU, and subsequently FirstEnergy, appear to have managed the Pennsylvania provider-of-last-resort and New Jersey BGS procurement in a fair and equitable manner.
- GPU's Pennsylvania provider-of-last-resort procurement strategy and provider-of-last-resort procurement implementation activities were consistent with those employed by GPU in meeting JCP&L's BGS obligations. In both cases targets were set, first using the X-method, and then using the HOST method. Procurement activities were governed by the status of committed supplies against target levels and expectations of price movements using similar considerations in both jurisdictions. Differences in actual targets and procurement levels are attributed to differences in the underlying makeup of the customer base and their associated load profiles in Pennsylvania and New Jersey, rather than any attempt to manage costs in Pennsylvania or shift costs from Pennsylvania to New Jersey.
- It was reasonable to include a need to avoid buying quantities large enough to move the prices upward in either the forward or spot markets, as an objective of the procurement strategy.
- The Company reasonably deviated from its fill target plan when it was faced with unusual market uncertainties or opportunities, including for the summer of 2001 and 2002, with the exception of [alleged] excess procurement of supply for the summer of 2001.
- JCP&L monitored short- and long-term market conditions and prices on a daily basis.

[CIB at 153-154, quoting Chapters I and VII of the Phase 1 Audit Report]

The Company did, however, take issue with the $11.7 million disallowance recommended by the Auditors in finding that the Company had imprudently exceeded its

fill (hedge) targets established for the summer months of 2001. As asserted by the Company, the alleged excess procurement was due to the introduction of the HOST model in February 2001, which together with declining forward prices, substantially reduced the hedge targets (the portion of the targets to be met by forward purchases) for the months at issue. However, the higher targets previously established by the X-model had already been procured, and the Company maintained that if it had sold the excess, it would have been forced to rely more heavily on the PJM spot market, since the Company's ultimate supply obligations had not changed. Increased reliance on PJM in turn could have exerted upward pressure on prices, especially at a time when PJM was imposing new, more stringent credit policies. (Id. at 155)

The Company also took issue with the Auditors' questioning the lack of an energy TPPA with the purchaser of its fossil units, maintaining that encumbering the sale with an energy TPPA would not have maximized the sale price of the units, thereby increasing stranded costs, contrary to the Company's (and Board's) divestiture objectives. Moreover, experience with Homer City, a large coal plant partly owned and subsequently divested by Penelec, assertedly indicated that a capacity only TPPA option was more advantageous, based on the indicative bids received when both energy and capacity TPPA options were offered to the bidders for that plant. (Id. at 155-157)

The Company additionally took issue with the Auditors' suggested disallowance of $5.6 million[75] for the Company's alleged failure to devote sufficient effort toward mitigating the cost of the Camden, Gloucester and Kenilworth PPAs. In the Company's view, this would have been a misplaced use of its NUG mitigation resources, given the small size of these projects and complicating factors such as the need to obtain the approval of county financing authorities and the New Jersey Department of Environmental Protection for changes in the projects' PPAs. Moreover, the 10 percent savings target assumed by the Auditors applied only to the above-market cost component, not the entire contract payment, and if corrected, the disallowance would be reduced to $2.4 million. (Id. at 160-163) The Company also took issue with the Auditors' proposed Phase II review of the delay in the Bayonne closing and the Company's rejection of the Reliant proposal, as well as the Company's alleged failure to avail itself of weather hedges. (Id. at 163; 157-159)

In contesting other issues raised by the Auditors, the Company asserted that the determining factor in setting the period over which Oyster Creek costs were to be amortized was the date the unit's operating license would expire in the absence of a sale or shutdown (December 31, 2009), and thus that the 11 years noted in the Final Restructuring Order was simply a rounded amount. In defending its use of the 14.64% return in calculating the revenue requirement of the fossil units, the Company asserted that this was the pre-tax return that formed the basis for the unbundling of its rates, as approved in the Final Restructuring Order. (Id. at 167-169)

RPA

The Ratepayer Advocate was sharply critical of the Phase I Audit Report, asserting that it:

[75] Corrected to $5.7 million in S-40.

> lacks demonstrative evidence that it is the product of thorough and independent analysis. The Audit Report is riddled with instances in which key conclusions, definitions, and explanations are verbatim copies of material provided by the Company in either testimony or discovery responses. The appearance is one of wholesale adoption by the Auditors of the Company's representations without any independent analysis of those positions by the Auditors. As such, the Audit Report is only as strong as the Company's representations, and is weakened further in that it cannot demonstrate adequately that [the Auditors] in fact investigated or otherwise plumbed beyond the surface of the Company's actions.
>
> [RIB at 39]

The Advocate went on to cite several parts of the report, including language appearing in the "Findings and Conclusions" section, that were quoted verbatim, or nearly so, from testimony or discovery responses submitted by the Company without having been attributed to the Company.[76]

The RPA also faulted the report for not utilizing external benchmarks against which the Company's performance could be compared (RIB at 40), and questioned how the Auditors could have independently verified the information on which they relied, given the Company's alleged lack of record keeping and other documentation for what it did. (RIB at 44-46)

Staff's Position

At Staff's request the Audit Report included a comparison of the cost of the Company's "discretionary" energy and capacity purchases[77] made during the first three years of the transition period to the cost of purchasing the same energy and capacity from PJM. (S-38, Appendix B) The comparison was based on data supplied by the Company, and showed that the actual cost of the Company's discretionary purchases during this period was $1,119 million, as compared to $793 million if the energy and capacity purchases were priced at PJM prices. The apparently rounded difference of $327 million represented an increase of over 40%. The Auditors noted that this analysis was retrospective in nature, and was not considered in their determination of prudence.

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[76] See RIB at 40-44. When this issue was raised at the April 28, 2003 hearing, the Auditors (Laros) testified that the "material in here [the unattributed quotes] is felt by me to be a valid description of the factual information we were provided to present as verified through interview notes or interviews or other discovery...And I didn't feel it was necessary to recraft what I thought were apt descriptions of various matters." (13T 33 8 to 15 as quoted in RIB at 40) In its Reply Brief the Company also defended the Auditors' use of the unattributed quotes, asserting that once the information on which the Auditors' conclusions were based had been independently verified, "there was no reason to re-invent the wheel (or re-write the treatise) if the point had already been cogently articulated by the Company. Use of common language to express independently-derived conclusions does not in any way suggest a lack of independence." (CRB at 100; also see pages 98-99, 101)

[77] Energy and capacity purchases other than those made pursuant to TPPAs and pre-transition PPAs with other utilities and NUGs, i.e., non-TPPA discretionary purchases are the combination of two-party, bilateral and PJM purchases made by the Company in carrying out its BGS procurement strategy.

Moreover, they averred that the PJM prices were based "on existing market conditions and do not reflect changes in price which would likely have occurred with increased volume of PJM purchases." (Id. at B-1)

As discussed more fully below, Staff effectively subsumed the Auditors' recommended BGS disallowance of $11.7 million within its proposed BGS disallowance, which was based on the PJM benchmark and a review of the Company's procurement during the period from December 1999 through July 2000 in addition to the summer months of 2001 and 2002 analyzed by the Auditors. Staff agreed that the Company's use of the 14.64% pre-tax return in calculating the revenue requirement of the fossil units had not been authorized by a Board Order, and that the delayed Bayonne closing and the Reliant NUG proposal rejected by the Company should be reviewed further in Phase II of the audit. Staff did not agree, however, with the Auditors' suggested disallowance of $5.7 million of above market NUG costs.

4. SBC Deferred Balance/Charges

(a) Nuclear Decommissioning Funding

As permitted by the EDECA, nuclear decommissioning costs ("NDC") are one of the categories of costs recoverable by the SBC. N.J.S.A. 48:3-60.a.(2). As shown in Exhibit S-4, the Company proposed reducing the annual level of TMI-1 decommissioning-related charges included in the SBC, increasing the level of annual TMI-2 and Saxton decommissioning funding, and keeping the level of Oyster Creek decommissioning-

the Saxton decommissioning is no longer being funded by Met-Ed and Penelec, the Company's Pennsylvania affiliates, and thus it would be unfair to New Jersey ratepayers to ask them to continue to fund this cost. (S-8.)

(b) Universal Service Fund (USF)

Since the implementation of the appropriate USF charge was not to occur before August 1, 2003, JCP&L proposed to defer recovery of its costs, including interest, to implement the permanent USF program until after the Company receives the Board Order in the pending USF proceeding. Neither the RPA nor Staff addressed this issue.

(c) Demand Side Management (DSM)

JCP&L recovers its regulated DSM costs through the SBC. The Company requests an annual recovery of $38.8 million, resulting in a decrease in its DSM of over $15 million. The RPA did not oppose the Company's request, but did address the Company's request for lost revenues as part of the Company's energy efficiency programs. Staff did not oppose the Company's request.

(d) Consumer Education (CED)

The Company proposes to recover all Board approved costs associated with the CED, along with any carrying charges, beginning August 1, 2003. The Company estimates that the CED costs will total approximately $5.6 million and proposes to recover these costs through a base charge of 0.0278 cents per kwh.

The RPA would disallow any recovery by the Company of its CED costs for Year 2 and Year 3. The RPA believes that the statewide CED failed to achieve its goals of increasing awareness among gas and electric consumers in the critical areas of energy competition, alternate energy suppliers, energy conservation and efficiency, and the availability of financial assistance to eligible consumers.

Staff believes the Company is entitled to recover its costs associated with the CED and agrees with the Company's proposed CED Tariff Rider of 0.0278 cents per kwh.

(e) Uncollectibles (UNC)

In accordance with the Stipulation of Settlement approved by the Board in its Order in the Customer Services proceeding, Docket No. EX99090676 ("CAS Stipulation"), recovery of the Company's uncollectible costs was moved out of its delivery charge and into an adjustable rider within the SBC on August 1, 2001. As agreed to in the CAS Stipulation, the adjusted five year average of FERC Account 904 totaling $4.92 million was moved into the SBC. The Company intends to continue the UNC charge at its current level, periodically truing-up its actual uncollectible expenses to UNC revenues to determine whether the Company's UNC is over-collected or under-collected. Neither Staff nor the RPA opposed the Company's proposal.

5. Other Issues

(a) Interim Recovery of BGS/MTC Deferred Balances

At its public meeting held on March 20, 2003, and as memorialized in a Secretary's Letter to the ALJs hearing the deferred balances cases of the four utilities dated March 25, 2003, the Board decided to recall a number of issues related to the securitization and/or amortization of each utility's deferred balances. Specifically, the Board's letter indicated that it was recalling the following:

> the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized, and for those balances to be amortized, what is the appropriate length of the amortization and the interest rate. In addition, the Board is recalling the issue of whether all or part of the prudently incurred deferred balances are legally eligible for securitization under EDECA. The individual Administrative Law Judges should be making findings as to what the level of prudently incurred deferred balances is for each utility.
>
> The Board will be making findings as to the appropriate transitional amortization and interest rate for such deferred balances between August 1, 2003, until such time as a final Board decision is made on the issue of securitization v. amortization and any authorized transition bonds are issued. To the extent that the parties have offered opinions on the setting of transitional amortization and interest rates in their cases, those portions of their briefs will be reserved to the Board and decided by the Board as part of their final rate Order. The issues that are being recalled will be considered by the Board in the individual securitization petitions filed by the individual utilities. To date, only two utilities, Rockland Electric Company and JCP&L, have made such filings with the Board. Individual procedural schedules will be set for each of the securitization proceedings.
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> [Letter to the Hon. Richard McGill, Irene Jones, William Gural and Diana C. Sukovich, Administrative Law Judges, from Kristi Izzo, Secretary of the Board, dated March 25, 2003]

Accordingly, and consistent with its recommendation made in Public Service Electric & Gas Company's, Atlantic Electric's and Rockland Electric Company's deferred balance proceedings, Staff recommended interim deferral recovery, i.e., the recovery of JCP&L's deferred BGS and MTC balances during the period from August 1, 2003 until the date of securitization closing, or such other date on which amortization in lieu of, or in combination with securitization of these balances begins, as determined by the Board, based on an amortization period of 10 years. With respect to carrying costs, Staff recommended that in view of the short period in which the transitional recovery is expected to be in effect, the rate on 7-year treasuries plus 60 basis points previously authorized by the Board be reduced to the rate on 1-year treasuries plus 30 basis points,

or to about 1.6%,[79] based on the yields reported in the Federal Reserve Statistical Release dated March 3, 2003. Moreover, the amortization should be determined net of tax.[80]

Applying this recommendation to the Company's combined BGS and MTC balance after reflecting Staff's proposed BGS disallowance of $152.5 million ($535.3 million),[81] yielded levelized annual deferral recovery of $56.4 million.[82] On a per kwh of sales basis this equated to 0.2814 cents per kwh, based on normalized 2002 sales of 20,042 Gwh.[83]

(b) RAC and Other Interest Calculations

The Company argued in its Initial Brief that the interest rate of 6.25% previously authorized by the Board for accruing interest on the unamortized balance of RAC costs should be retained, i.e., not changed to the yield on constant maturity 7-year Treasury notes plus 60 basis points, as recommended by the Advocate's witness Richard LeLash. If, however, a change were to be made, the rate should be increased to the Company's overall cost of capital, as argued by Company witness Filippone in his Direct Testimony. (CIB at 187 citing JC-3 at 18-20) Mr. LeLash had also proposed that interest be compounded annually, and the Company did not object to this proposal, provided the compounding was applied only prospectively, and uniformly to all of the Company's deferred balances, not just the RAC. (CIB at 188)

Staff agreed that the use of the 7-year Treasury rate was appropriate as long as the recovery of RAC costs continued to be based on a 7-year rolling average, and that the rate should be changed annually at the time the RAC factor is changed. Consistent with its recommendation in the deferred balance proceedings of the other utilities, Staff also supported annual compounding, as well as calculating interest monthly on the monthly beginning and ending balance of all deferrals, including the Company's deferred balances incurred during the transition period.[84] (SRB at 7)

Going forward, i.e., effective August 1, 2003, for all non-RAC deferrals, Staff recommended accruing interest at the Company's actual average cost of short-term debt (debt due in one year or less), or if no short-term debt were outstanding, the rate available on comparable temporary cash investments. Moreover, both the interest rate and the balance to which it was to be applied would be determined "net of tax" (reduced by deferred income taxes associated with the deferred costs and deferred interest

[79] Later updated to 1.3%

[80] As illustrated in Exhibit 2 attached.

[81] $687.8 million from Schedule SDM-1A of Exhibit JC-13 ("12+0" Update) less Staff's recommended disallowance of $152.5 million

[82] Determined by dividing $535.3 million by the annuity factor 9.49859, where n = 10 years and i = 0.9464 (1.6%, net of tax).

[83] From Schedule SDM-5 of Exhibit JC-13 ("12+0" Update).

[84] The Company calculated interest on its deferred balances annually during the transition period.

expense).[85] While the rate and method of calculating interest on RAC deferrals were ultimately stipulated to by the parties,[86] other than Staff, the parties did not address the post-transitional interest rate and methodology to be applied to the Company's other deferred balances.

VI. DISCUSSION AND FINDINGS – DEFERRED BALANCES

A. PRUDENCY OF BGS PROCUREMENT

Discussion:

Through the testimony of its witnesses Mascari, Stathis and Graves, the Company asserts that it has demonstrated that its BGS procurement strategy and the implementation of that strategy during the three years ended July 31, 2002 was reasonable and prudent. Moreover, with the exception of what the Company characterizes as only minor concerns, including a recommended disallowance of deferred BGS costs of $11.7 million, the Auditors have also found the Company's procurement strategy and its implementation b have been reasonable and prudent during that period. The Advocate and Staff disagree, and have proposed substantial BGS disallowances of $239 million and $152.5 million, respectively.

The Advocate's recommended disallowance is based on a comparison of the cost of the Company's BGS energy purchases to the equivalent costs incurred by its Pennsylvania affiliates, Met-Ed and Penelec, during the same three-year period. Like the Company, these utilities had divested their generating assets, and thus were faced with the same responsibility of obtaining PLR supply for those of their customers not electing to take generation service from third party suppliers. The Advocate's disallowance was quantified by comparing the average prices the three companies paid for energy purchases other than contractual purchases from NUGs and divested generating units during the period. On that basis the cost of JCP&L's purchases averaged $45.88 per Mwh, or about 14% to 15% more than the $39.90 and $40.26 paid by Met-Ed and Penelec, respectively. In each case, the amount paid does not include capacity costs, i.e., is for energy only.

The Advocate attributes the higher cost of the New Jersey purchases to the differing regulatory treatments of unrecovered BGS/PLR costs in the two states. Unlike New Jersey, where as part of the restructuring plans approved by the Board the state's

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[85] While the Company deducted deferred income taxes associated with the deferred costs from the deferred balances in calculating interest during the transition period, it did not deduct deferred taxes associated with the deferred interest.

[86] As noted above, the RAC Settlement provides for interest on the over or under-recovered deferred RAC balance to be calculated on a monthly basis upon the average of the beginning and ending monthly balances of deferred RAC costs, less accumulated deferred income taxes associated therewith, at a rate equal to the rate of seven-year constant maturity Treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year, plus 60 basis points. Interest shall be compounded annually on August 1 of each year, commencing August 1, 2004, by adding the accrued interest from the prior twelve-month period to the principal balance on which interest is calculated. The interest shall be calculated on a prospective basis only, beginning 45 days after the issuance of a Final Order approving the RAC Settlement.

electric utilities were permitted to defer such costs for future recovery, deferrals were not permitted in Pennsylvania. Thus, as indicated above, unrecovered PLR costs in Pennsylvania had to be borne by stockholders. Accordingly, the Advocate asserts, there was a strong incentive to control costs in Pennsylvania that was lacking in New Jersey. The Advocate additionally maintains that the computer models employed in setting the targeted levels of the Company's on-peak forward energy purchases were flawed, in that they had as their objective minimizing the effect of BGS/PLR procurement on pre-tax earnings (the difference between BGS/PLR revenues and costs), in contrast to what the Advocate maintains is the more appropriate objective of minimizing costs alone. When revenue exceeds costs (as it typically does in low load months), and although the Advocate does not suggest that the Company actively sought to achieve this perverse result, the earnings-based objective of the Company's models could, in theory, *increase,* not reduce costs. In addition to this assertedly flawed objective, the Advocate maintains that the models were inconsistently applied, and that their results were ignored outright in some instances.

The Advocate also faults the Company for inadequately documenting its actions and failing to perform periodic retrospective reviews of its BGS performance, thus depriving itself of potentially valuable feedback that could have resulted in improvements in its procurement activities during the transition period. In particular, the Advocate cites the Company's failure to develop internal and external benchmarks against which its performance could be compared and measured.

With respect to the Audit Report, the Advocate asserts that the Auditors' findings and conclusions relied too heavily on the Company's representations, even to the point of quoting the Company's testimony and discovery responses verbatim without proper attribution. Moreover, the Company's alleged lack of adequate documentation assertedly prevented the Auditors' from performing a truly independent audit.

Staff agrees with the Advocate on several points, including the asserted inappropriateness of the objective of the Company's models employed in setting monthly targets for forward purchases of on-peak energy. While minimizing the impact of PLR procurement on earnings may have been defensible in Pennsylvania, given the regulatory treatment of unrecovered PLR costs there, in Staff's view it clearly was not in New Jersey, where, in addition to permitting deferrals, the Board authorized the accrual of carrying costs on the deferrals at a relatively generous interest rate. If the interest actually paid was less than the Board's allowance, the deferrals could, in fact, have had a positive impact on earnings. Staff was also less certain that the models' assertedly inappropriate objective did not actually increase costs, a concern applicable to the HOST model in particular, given its complexity that in Staff's view effectively precluded all but a cursory review in this proceeding. On the other hand Staff avers that there is less ambiguity in identifying another of the models' asserted flaws, namely that they appeared to expressly allow forward purchases in excess of the Company's projected on peak energy requirements, thereby potentially exposing it to the risk of having to resell the unneeded energy at a loss.

Moreover, Staff maintains that this is exactly what happened in the months of June and July 2000. After analyzing a retrospective review of the Company's BGS procurement presented by the Brattle Group, the Company's consultant, in September 2000, Staff found that the Company purchased about 50% more on peak energy than it needed in these months at an average cost of $63.54 and $114.02 per Mwh, respectively, thereby

incurring a loss in these two months alone of $53 million when the excess energy was resold in the PJM spot market for approximately $33 per Mwh. For the entire eight month period reviewed (the months of December 1999 through July 2000), the cost of the Company's on peak energy purchases exceeded what the cost of the equivalent energy would have been if purchased in the PJM spot market by approximately $82 million ($148.4 million versus $66.4 million). A difference that large, Staff avers, should have triggered a rethinking of the Company's basic procurement approach in contrast to implementing the relatively modest enhancement of dollar cost averaging recommended by the Brattle Group, which was estimated to save about $12 million over the period analyzed, as compared to the Company's hedging strategy then in place.

Staff accordingly found this lack of attention to the results of the strategy itself - an achieved cost of BGS purchases more than *twice* the cost of the equivalent energy if it had been purchased from PJM - to have been patently imprudent. In the plain words of Staff, "a reasonable person would have concluded that under its procurement methods, the Company was both purchasing more forward energy than it needed and paying far too much for it." Other than a passing reference to a cool summer in a footnote, no analysis of the reasons for the difference appears to have been

both cases, however, only the cost of so called "discretionary" purchases, i.e., purchases exclusive of contractual purchases made under PPAs with NUGs, and TPPAs with the owners of the divested generation units,[87] were considered.

Staff's comparison showed that the Company's BGS procurement costs would have been approximately $330 million lower during the first three years of the transition period if the Company's discretionary purchases had been made at the average price of equivalent capacity and energy purchased from PJM (approximately $42 per Mwh), as compared to the average price actually paid (about $60 per Mwh). Staff then reduced the $330 million difference by offsetting it with the relatively favorable results achieved from the Company's TMI-1 and Oyster Creek TPPAs, as well as the payment it received from re-negotiating the PPA with the Bayonne NUG project, yielding a net recommended BGS disallowance of $152.5 million. In estimating the savings from the TPPAs, the same method used in quantifying the disbenefit attributed to the discretionary purchases was applied; that is, the lower amount paid under the TPPAs was compared to the higher cost of purchasing the equivalent energy and capacity from PJM, and the difference subtracted from the discretionary purchase disbenefit.

In responding to the Advocate's recommended BGS disallowance, the Company argues that the average price it paid for its discretionary BGS energy purchases exceeded the comparable prices paid by its Pennsylvania affiliates because its peak requirements were higher, the level of its customer shopping significantly lower, and its summer air conditioning load proportionately greater than theirs. Additionally, the Company was assertedly subject to higher congestion costs due to transmission bottlenecks that typically impede PJM's west to east power flows. In rebuttal, and while conceding that the Company's load factor is lower than that of the Pennsylvania companies and that it may face higher congestion costs than they do, the Advocate avers that the Company did not quantify the effect of either factor. Moreover, the Advocate does not agree that the higher level of customer shopping in Pennsylvania made the PLR load of the Pennsylvania companies any less costly to supply, nor does it agree that the cost differences between the two states, which tended to be more pronounced in the non-summer months, could be explained by the Company's higher air conditioning load. While the Company did provide an estimated range of the impact of congestion costs, Staff agrees with the Advocate that the other factors cited by the Company had not been adequately quantified. Nonetheless Staff finds that they could plausibly account for the Pennsylvania/New Jersey cost difference, and thus recommends that its more general PJM benchmark be used as the yardstick against which the Company's performance should be measured.

The Company vehemently opposes the use of the PJM benchmark, indeed any external benchmark at all in judging the reasonableness and prudence of its BGS performance, maintaining instead that only the adequacy of its procurement plan itself and the extent to which it was followed should be so judged, a position concurred in by the Auditors. To compare its performance to PJM prices after the fact, with the benefit of hindsight, is, in the Company's view, nothing more than Monday morning quarterbacking.

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[87] In Atlantic Electric's deferred balance proceeding, discretionary purchases were defined more broadly, i.e., they included purchases made under TPPAs, which Atlantic failed to obtain from the purchasers of its divested generating units, a significant issue in Atlantic's deferred balance proceeding that was not present to the same extent here. With the possible exception of not having secured an energy as well as a capacity TTPA with the purchaser of the Company's fossil units, Staff found that JCP&L's TPPAs turned out well, as discussed above.

As to the high forward prices it paid for energy secured for the months of June and July 2000, the Company defends them on the basis that even higher prices had been experienced in PJM in July 1999. Moreover, there was also the before-the-fact possibility that prices could skyrocket as they did in the chaotic California spot market in 2000 and 2001. Additionally, if the Company (and its Pennsylvania affiliates) had purchased all of their requirements from PJM, PJM prices assertedly would have been higher than they actually were due to the increased demand, and in any event the prices actually experienced reflected only one of any number of market outcomes, depending on such factors as weather and gas prices that cannot be known in advance.

With respect to Staff's contention that the Company's models appear to have allowed the establishment of monthly on-peak targets in excess of its peak load projected for the delivery month, the Company concedes that this could have been the case if the targets are compared to the average monthly peak load (the average of the 16 on peak hours on all non-holiday weekdays during the month), but not when compared to the hourly peak demand for the month, the peak load to which its models were keyed. Nor did the adoption of the lock and load strategy represent a shift to a more nearly cost-based procurement strategy, as suggested by Staff, but rather the setting of price points approaching marginal costs that when reached, were intended to trigger accelerated forward purchasing. As to not saving the price quotes it received when entering into forward purchases other than those of the winning bidder, the Company maintains that this was unnecessary in light of its procedures that insured that the purchases were made at prevailing market prices, a view concurred in by the Auditors.

Findings:

Pennsylvania vs. New Jersey BGS/PLR Procurement Costs

While the Advocate attributes the relatively better procurement results achieved by the Company's Pennsylvania affiliates to the regulatory treatment accorded unrecovered PLR costs in Pennsylvania, we, like Staff, find the factors cited by the Company in explanation of the differing cost profiles of the companies to be plausible, if not totally convincing in view of the Company's less than adequate quantification of the differences. That the same procurement team and methods appear to have been uniformly employed and applied in both states, at least until the Board-ordered separation of the Company's procurement function from the parent company's after the FirstEnergy merger, lends support to this view. We also note that the Advocate's and Staff's recommended disallowances are not mutually exclusive. Staff's more general PJM benchmark inherently subsumes whatever differences may have resulted from preferential treatment of the Pennsylvania companies, if indeed there were any, and accordingly we find Staff's recommended PJM benchmark to be the more appropriate of the two yardsticks to use for the purpose of quantifying imprudence on the Company's part.

Inappropriateness of the Company's Modeling Objectives

Both the Advocate and Staff find the objective of the Company's models, minimizing the effect of BGS/PLR procurement on pre-tax earnings, to have been inappropriate, and we concur. While recognizing that there is clearly merit to the Company's argument that a number of weather, price and demand scenarios should have been evaluated, in our view they could have been considered just as well by models having the more

appropriate objective of minimizing costs (maximizing the difference between revenues and costs when revenues exceed costs, for example). From a New Jersey perspective, that would have been equivalent to minimizing the Company's deferred balance, an especially appropriate objective in view of the fact that while the Company admittedly faced disallowance risk in New Jersey, there was either no, or a potentially favorable earnings impact from the deferrals as such, for the reasons noted by Staff. Moreover, we fail to see why the same cost minimizing objective would not have been the better choice to employ in Pennsylvania as well. While not necessarily minimizing earnings volatility, it appears to us that a cost minimizing objective would have minimized the absolute effect of unrecovered costs on the earnings of the Pennsylvania companies as compared to the objective actually employed, minimizing the difference between revenues and costs.

We also do not view the model's apparent undue emphasis on reducing volatility to have been appropriate, clearly not from a ratepayer perspective, inasmuch as the Company's shopping credits remained fixed during each year of the transition period. Moreover, as Staff points out, pronounced seasonality in the cost of electric supply is normal and unavoidable, and the Company was fully compensated for the interest it may have incurred in financing seasonal increases in its BGS deferred balance during the transition period via the Board's relatively generous allowance of carrying costs at the rate on 7-year constant maturity treasury notes plus 60 basis points. Thus in addition to reducing the impact of BGS/PLR procurement on pre-tax earnings, we find that reducing the volatility of earnings was another of the models' objectives that was not necessarily relevant nor appropriate in New Jersey.

As distinguished from volatility as such, the Company asserts that a key objective of its procurement strategy was to minimize its (and from a cost standpoint, its ratepayers') exposure to price spikes and potentially extremely high spot prices, citing those experienced in PJM in July 1999 and in the chaotic California energy market in 2000-2001. As the Company points out, reducing risk via financial instruments and forward contracts was expressly contemplated in the Final Restructuring Order, and the Board recognized that the cost of these instruments and forward purchases could exceed the cost of spot market purchases. In the Company's case, however, the question is, by how much? In Staff's view, by too much, as evidenced by its analysis of the Company's forward purchases of on peak energy for the delivery months of June and July 2000. When confronted by forward prices in excess of 11 cents per kwh, Staff maintains that the Company should have concluded that it was not likely to do any worse by relying on the spot market, and should have done so rather than entering into forward contracts at those prices, and we agree. Moreover, beyond these two months we find the amounts paid for the Company's discretionary BGS purchases throughout the transition period to have been excessive, as discussed below, even after making a generous allowance for the risk premium demanded on forward purchases.

As to the California experience, we view that to have resulted from a number of factors unique to that state,[88] as evidenced by the fact that it has not been repeated in other

[88] A poorly designed spot market was only one of several factors that led to the California energy crisis that began in the early summer of the year 2000. See, for example, *The History of Electricity Restructuring in California*, Blumstein, Friedman and Green, August 2002, where the authors note that such factors included "a supply/demand imbalance combined with a retail price freeze that prevented supply and demand from equilibrating, exogenous increases in the prices of some key inputs [i.e. natural gas, as discussed elsewhere in the report], poor design of the

jurisdictions. Nor have the high on-peak PJM prices experienced in July 1999 been repeated on a sustained basis, suggesting that they, too, may have resulted from market immaturity or imperfections that have long since been worked out. In any event, we do not believe that a one-time occurrence of on peak PJM spot prices averaging 15 cents per kwh can be defensibly cited to justify paying prices well above the much lower PJM prices subsequently experienced in the months immediately following July 1999, i.e., in August 1999, typically a month in which prices are just as high, if not higher than they are in July. In that month, as reported by the Company in monthly reports filed with the Board, PJM's average on-peak billing rate to GPU, as it was then called, was 5.37 cents per kwh. Moreover, the average on peak billing rate declined steadily thereafter, to 3.08, 2.71, 2.26 and 2.13 cents per kwh in the months of September 1999 through December 1999, respectively.

Forward Purchase Targets in Excess of On-Peak Load

Staff asserts that the Company's models appear to have allowed forward purchases in excess of the Company's projected on peak energy requirements, thereby potentially exposing it to the risk of having to resell the unneeded energy at a loss. That, Staff avers, did in fact happen in setting the targets for the months of June and July 2000,[89] as discussed above, and the excess purchases in combination with the excessive prices paid for them assertedly increased the Company's BGS costs by $53 million alone in those two months. The Auditors' recommended disallowance of $11.7 million was also attributable in part to excess forward purchases targeted for the following summer (the months of June, July and August 2001), but in quantifying their disallowance, the Auditors compared the cost of he forward purchases actually made to the cost of forward purchases that would have been made if the Company had not deviated from its fill targets (including an excess of 274 Mw targeted for June 2001), as compared to reselling or purchasing the energy from PJM.

While conceding that the hedge targets established by its models could exceed the Company's monthly average peak load, the Company states that the targets did not exceed the single peak hourly load projected for the delivery month, inasmuch as that was the peak load on which the models were based. That in our view does not excuse the Company for knowingly contracting for excessive forward purchases, as stated

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electricity market, the exercise of market power by generation owners, and inept regulation." (pg. 21) With respect to the criticism leveled against the spot market, the authors go on to note that "One element that has been widely identified as a problem in the [California] market rules is 'over reliance on the spot market' resulting from a 'prohibition' on forward contracting. Apparently the FERC believed, when it issued its December 15 order...that the system was 100% reliant on the spot market. This was never the case since prices paid for utility-owned generation and QFs were determined by regulatory side agreements. Also, as noted earlier, the PX [the California Power Exchange, i.e., the spot market] had a forward market that opened in 1999. The utility distribution companies could purchase 20% of their requirements in the PX forward market with recovery of the cost guaranteed by the CPUC [California Public Utilities Commission]; The utilities were not prohibited from making forward purchases in excess of 20%, but the recovery was not guaranteed by the CPUC." (pgs. 24-25)

[89] As noted above, the Company's hedge target for the month of July 2000 was 124% of gross peak load (load not reduced by committed supply) and 151% of net peak load after deducting committed supply.

above by its consultant in reference to the July 2000 hedge targets, but simply raises the question as to why the single hourly peak load was used for hedging purposes rather than the average. Forward contracts sized on the hourly peak load *guarantee* that there will be substantial amounts of excess energy not utilizable in the remaining on peak hours, and beyond a fleeting reference to risk management theory in a footnote, the Company did not provide any justification for its use of the peak hourly load as opposed to the average, most importantly from a cost standpoint. Staff's analysis on the other hand, and the Auditors' to a lesser extent, show that the Company's on peak energy purchases were demonstrably excessive, and imprudently increased its BGS costs in the periods analyzed.

"After-the-Fact" Performance Reviews and PJM Benchmark

In opposing the use of external benchmarks in general, and the PJM spot market in particular to measure the cost-effectiveness of its BGS procurement, the Company maintains that only the adequacy and execution of its procurement plan itself -- its management, policies and procedures, models and other tools, staffing, training and the like, are relevant to the Board's prudency determination in this proceeding. On that basis the Company asserts that its BGS procurement during the first three years of the transition period was reasonable and prudent, and that the Auditors have, with minor exceptions, concurred in this assessment.

While not denying that the criteria cited by the Company are important, and while also recognizing that an after-the-fact review is vulnerable to the charge of Monday morning quarterbacking, the Advocate and Staff nonetheless maintain that it is equally important to consider the *results* of the Company's BGS procurement, both during the transition period as it unfolded, and in performing this post-transition prudency review required by the Final Restructuring Order. A results oriented review in turn necessarily requires the establishment of a benchmark against which the results are to be measured.

As to the Company's failure to periodically review its performance during the transition period, the Advocate asserts that such reviews were essential to assessing the effectiveness of the Company's procurement plan and for implementing needed modifications when indicated: "The Company should have been conducting after-the-fact comparisons throughout the BGS procurement period because information on the performance of a strategy is vital to determination of whether the strategy should be continued. If every transaction of a particular type that JCP&L made turned out to be uneconomic, prudent management would require that the use of that type of transaction be re-examined, restricted or stopped entirely." (R-59 at 32, 3 to 16)

While the Brattle Group reviewed the Company's procurement experience over the eight-month period from December 1999 through July 2000, that review did not have as its focus how the Company was doing compared to an appropriate external benchmark, i.e., the PJM spot market. Instead, the cost of the Company's forward purchases was compared to the slightly lower cost that assertedly would have resulted if the dollar cost averaging recommended by the Brattle Group had been employed during the period reviewed. As discussed above, a comparison to PJM prices over the period indicated that the cost of the Company's purchases was more than twice the cost of the equivalent energy if purchased from PJM. A simple analysis of the reasons for the difference in turn revealed that of the $82 million total difference, excess energy purchases – purchases known to be in excess of the Company's requirements before the fact and not

the result of forecast error – accounted for $53 million. This analysis, Staff maintains, should have been performed, and should have triggered a review and modification of the Company's models to eliminate the possibility of purchasing forward energy in excess of the Company's projected requirements. One possible modification suggested by Staff would have been to increase reliance on spot market purchases from PJM. Another modification suggested by the Company's explanation of the reason for the excess purchases in its Reply Brief would have been to change from the single hourly peak load to the monthly average as the basis for establishing the hedge targets for the delivery months.

The Auditors' retrospective review of the Company's forward purchases for the summer months of 2001 also found that it had incurred excessive BGS costs due in part to excess forward energy purchases for those months. Thus a second opportunity to potentially modify the Company's procurement methods and models was missed due to its failure, in this instance, to have performed any retrospective review of its performance in these important months at all.

More generally, based on data supplied by the Company, Staff compared the cost of the discretionary component of the Company's BGS procurement over the first three years of the transition period to the "default option" of purchasing the same energy and capacity from PJM, and found that if priced at the PJM prices experienced during the period, the cost of the discretionary purchases would have been $329 million lower than the actual cost of the Company's purchases. The Company and the Auditors assert that such a comparison is flawed because it assumes PJM prices would not have changed as a result of the Company's (and its affiliates') increased PJM purchases. The Company avers that due to the increased demand, PJM prices would have increased, and while the Auditors did not state that prices would have increased, they maintained that in any event they would have been different. Staff on the other hand argues that the increased supply in the absence of the Company's forward purchases would have exerted downward pressure on PJM prices. Moreover, by avoiding the risk premiums imposed on forward purchases, the Company would have enjoyed an additional benefit. Although not noted by Staff, by purchasing in real time, the Company would also have avoided the losses incurred on the resale of the excess forward energy noted above, as well as potential additional losses attributable to forecast error.

We agree with Staff and the Advocate that the Company should have been periodically reviewing and benchmarking its performance during the transition period for the reasons cited by the Advocate. We also find the use a benchmark for assessing the cost-effectiveness of the Company's procurement over the first three years of the transition period to be appropriate, indeed the only way of quantifying a finding of imprudence, a point recognized by the Auditors.[90] We additionally find the cost of energy and capacity purchased from the PJM spot market, the default option, as Staff puts it, to be appropriate for that purpose. As to the question of whether PJM prices would have increased as a result of the Company's increased spot purchases, as maintained by the Company, or decreased due to the increased supply no longer sold forward, as suggested by Staff, a computer simulation of the PJM spot market, both with and without the increased purchases and forward supply, may have shed additional light on this issue. However, in the absence of such a simulation or other record evidence that

[90] At the hearing on April 28, 2003 (13T 80-5 to 80-10) subject to possible adjustment to reflect the factors discussed on the preceding pages of the transcript.

would support the Company's contention, we find Staff's argument both plausible and persuasive, i.e., that the supply no longer devoted to fulfilling the Company's forward contracts would have instead been marketed in PJM, which, if all else remained equal, would have acted to reduce prices. More probable in our view, however, is Staff's contention that in all likelihood this increased supply would simply have been purchased by the Company. That is, we find plausible Staff's observation that the Company would in all probability have obtained the same output from the same facilities, only via the market mechanism of PJM in contrast to contractual purchases in the forward market.

Having said that, we also recognize that it was reasonable for the Company to have hedged a portion of its BGS requirement, and that it could have incurred increased costs as a result of such hedging. Moreover, this possibility was also recognized by the Final Restructuring Order. However, even assuming a hedge premium over spot as high as 23%, the average ratio of forward to spot prices determinable from Mr. Graves testimony,[91] the Company still paid about $144 million more than it should have, in that the actual cost of its discretionary purchases exceeded the cost of equivalent PJM purchases by 41%, a clearly excessive premium in our view.[92] We also note that the $144 million difference is reasonably close to the disallowance recommended by Staff. As a final check on the reasonableness of the PJM benchmark, we note that the energy and capacity component of the year four auction price, at approximately 4.29[93] cents per kwh was close to the 4.25 cents on which Staff's recommended disallowance is based.

Inadequate Documentation and Inconsistency of Model Application

In asserting that the Company's modeling process was seriously flawed, the Advocate maintained that the Company shifted strategies frequently in a comparatively short period of time and failed to implement even the most basic review and control measures. (RIB at 7-8). Moreover, the Advocate found the X-method to be flawed in that it did not seek to minimize costs and was applied in a manner inconsistent with its initially stated approach. (Id. at 12-15). The Advocate additionally maintained that the HOST model was run using risk tolerances not supported by the Company's own consultants and without clear direction as to target levels, nor, the Advocate asserted, did the Company adequately review model inputs crucial to the determination as to whether the model was effective. (Id. at 16-20).

After giving consideration to all of the above, we **HEREBY FIND** as follows:

1. The objective of the Company's models, minimizing the effect of BGS procurement on pre-tax earnings and the volatility thereof, was inappropriate for application in New Jersey;

2. In both instances analyzed in detail by Staff and the Auditors, excess forward purchases, a flaw apparently permitted by the Company's models, increased

[91] By comparing the average forward on-peak price ($46.76 per Mwh) calculated from Mr. Graves' Revised Exhibit FCG-8 to the average on-peak spot price calculated from that exhibit ($37.95 per Mwh).

[92] $144 million = $796 million from Table 1 times (0.413-0.232).

[93] 4.865 cents per kwh less 0.2 cents per kwh for ancillary services and 0.375 cents per kwh for transmission.

its BGS costs. To have knowingly committed to such purchases before the fact was patently imprudent;

3. The Company's failure to perform after-the-fact analyses of its BGS procurement performance during the transition period was imprudent;

4. The Company's documentation of its procurement decisions during the transition period was inadequate. Of particular concern is the Company's failure to keep records of how many bids it received, who the bidders were, and the prices they bid when the Company entered into its forward contracts;

5. The Company's employment of its various models during the transition period was so difficult to follow as to support the Advocate's assertion that the models were haphazardly and inconsistently applied; and

6. PJM energy and capacity prices experienced during the transition period are an appropriate benchmark for quantifying the effect of the Company's imprudence.

Accordingly, after reflecting estimated savings of $176.5 million achieved from the Company's TPPAs and the restructuring of its PPA with the Bayonne NUG project, we **HEREBY DISALLOW** $152.5 million of the Company's BGS costs incurred during the three year period ended July 31, 2002.

B. RETURN ON PRE-DIVESTITURE GENERATION INVESTMENT

Staff, the Advocate and the Auditors have questioned the Company's use of a 14.64% rate in calculating the return component of the revenue requirement of its fossil units and TMI-1 prior to divestiture. As noted above, except for Yards Creek and the Forked River turbines, which the Company continues to own, the fossil units were sold to Sithe in October 1998, and the sale closed in November 1999. Similarly, TMI-1 was sold to AmerGen in October 1998 and the sale closed in December 1999. The 14.64% pre-tax rate of return was accordingly applied to the Company's investment in these units during the period from August 1999 through the sale closing dates, and on its investment in Yards Creek and the Forked River units from August 1999 through July 31, 2003, the end of the transition period.

In the absence of a Board Order specifying the rate to be used, the Company employed the overall rate of return assumed in performing its cost of service study in the restructuring proceedings (14.64% pre-tax). Staff maintains this rate was effectively superseded by the 9.5% overall rate of return on which the reduction in the Company's average distribution rate from 3.70 cents per kwh to 3.45 cents was based.

We agree with Staff that the 9.5% rate of return effectively superseded the rate on which the Company's 1996 cost of service study was based, as indicated by the clear language of the Final Restructuring Order at 93:

> GPU has maintained in this proceeding that the 1996 COSS reflected in Schedule MRK-6 supports [an] average distribution rate of 3.70 cents. Nonetheless, it has agreed, as part of

> Stipulation 1, to an average distribution rate of 3.45 cents. The Board considers this reduction to be reflective, among other things, of a reduction in the distribution revenue requirements to reflect a more current overall cost of capital of 9.5%, which was supported by the RPA and other parties.

Accordingly, we **HEREBY ORDER** the Company to recalculate the return component of the pre-divestiture revenue requirement of the fossil units and TMI-1, as well as Yards Creek and the Forked River turbines, during the transition period to reflect the pre-tax equivalent of the 9.5% overall rate of return, and for that purpose the Company shall employ the methodology employed by Atlantic Electric.[94] Effective August 1, 2003, the return component of the revenue requirement of Yards Creek and the Forked River CTs shall be further adjusted to reflect our return finding in this proceeding (11.41% pre-tax, based on an overall rate of return of 8.38%, including an allowed rate of return on common equity of 9.50%).[95]

C. Mitigation Of Above-Market NUG Costs

As indicated above, the Ratepayer Advocate's witness Chernick asserts that the Company had failed to demonstrate any management of its NUG contracts to minimize NUG costs. (R-59 at 32-22 to 33-2) The Advocate expanded on this contention in its Initial Brief, asserting that the Company had "achieved no significant mitigation of NUG contract costs since 1997,"[96] (RIB at 31) and in particular, had failed to mitigate the above market costs of its three most expensive contracts, those with the South River, Lakewood and Bayonne projects having projected above-market costs during the transition period of $250 million, $114 million and $184 million, respectively. (Id. at 29-30) The Advocate also took issue with the Company's handling of the Reliant Proposal and for not mitigating the above market costs of its smaller NUG contracts more aggressively, as found by the Auditors. Accordingly, the Advocate proposed disallowing interest on the above-market NUG cost component of the Company's deferred balance, which it calculated to be $59.5 million. (Id. at 31; Schedule 2).

In its Reply Brief the Company faulted the Advocate for proposing a disallowance of this size for the first time in its Initial Brief, and for that reason alone (i.e., on procedural grounds) maintained that it should be dismissed. (CIB at 101). In support of its mitigation efforts the Company cited the Auditors' finding that "JCP&L has maintained a reasonable and prudent program for NUG mitigation since well before the [Board's 1993] *Towner* Order [Decision and Order dated April 12, 1993, in Docket No. EM91040844]" and, with limited exceptions not here relevant, has "prudently implemented its mitigation

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[94] Calculating the return quarterly, based on the actual weighted average embedded cost of debt and preferred, and a residual weighted average equity return determined by deducting the weighted debt and preferred costs from 9.5% and grossing up the residual equity return for income taxes. The investment in the generating units to which the pre-tax return is applied is also to be reduced to reflect monthly depreciation charges.

[95] SIB at 20, with a 9.50% rate of return on common equity.

[96] i.e., beyond the $6.3 million of savings achieved through the third quarter of 2002 from negotiating interim operating agreements with the Parlin and Newark Boxboard projects in March 2001. (RIB at 28).

program." (Id. at 102). In further support of the reasonableness of its mitigation efforts the Company cited the rebuttal testimony of witness Mascari, who reviewed the Company's continuing and previous mitigation efforts that began in the early 1990's, as evidenced by the pre-construction buyouts of the American Ref-fuel, Crown/Vista and Freehold PPAs, thereby achieving estimated ratepayer savings of $620 million on a net present value ("NPV") basis over the life of the terminated contracts. (JC-14 Rebuttal at 23-5 to 25-12) More recently, the Company negotiated pricing concessions from other project owners totaling approximately $60 million on the same NPV basis, and received an upfront payment of $25.4 million in return for negotiating revised pricing of the PPA with the Bayonne project. Id. That payment in turn was credited to the deferred balance in December 2002. (CRB at 102). Moreover, the Company files a quarterly report with the Board and the Advocate that provides the status of ongoing negotiations with each project owner as of the end of that quarter.[97]

As indicated above, the Auditors provided a comprehensive review of the history and results of the Company's NUG mitigation efforts in Chapter VIII of the Phase I Audit Report (S-38). While finding that the Company's mitigation efforts had complied with the Board's filing requirements, and that the Company for the most part had maintained a reasonable and prudent program for NUG mitigation since well before the Board's *Towner* Order, at least for its larger projects, the Auditors did conclude that the Company was less than aggressive in pursuing mitigation opportunities for the Camden, Gloucester and Kenilworth projects aggregating 50 Mw of contract capacity, and accounting for approximately $48 million of total above-market NUG costs of $770 million estimated for the period 2000-2003. (Id. at VIII-9, VIII-13; Exhibit VIII-2) Should the Board find that a disallowance related to these less than aggressive efforts was warranted, the Auditors suggested quantifying the disallowance at 10% of the contract payments made to the three NUGs during the transition period, or $5.6 million.[98] The 10% was assertedly the savings target internally set by the Company for its restructuring efforts. (Id. at VIII-16) As part of the Phase II Audit the Auditors also recommended re-examining the Company's rejection of a comprehensive NUG contract restructuring proposal made by Reliant Energy, and also investigating the reason for the delay in the receipt of the Bayonne PPA restructuring payment. (Id. at VIII-15)

In Supplemental Rebuttal Testimony filed on April 21, 2003, Mr. Mascari pointed out that the 10% savings target applied only to the above-market component of the NUG contract payments, not the entire amount, and if the 8% savings percentage actually achieved in restructuring the pricing terms of the Bayonne PPA were applied to the Camden, Gloucester and Kenilworth above market contracts payments, the disallowance suggested by the Auditors would be reduced to $2.4 million. (JC-14 Supplemental Rebuttal at 18-3 to 19-17)

Moreover, Mr. Mascari asserted that the Company had appropriately prioritized its NUG mitigation efforts in view of the uniqueness of the Camden and Gloucester projects, both of which are resource recovery facilities either owned, financed or subject to approvals by governmental entities (including the New Jersey Department of Environmental Protection) that complicate the negotiation process. (Id. at 20 to 21) The electric output of the Kenilworth project, a 15 Mw qualifying facility, has been limited to 5 Mw due to

[97] As directed by the Board in the Merger Order (its October 9, 2001 Order in Docket No. EM00110870 approving the GPU/First Energy merger).

[98] Corrected to $5.7 million at the hearing on April 28, 2003. (13T 29-2 to 7; Exhibit S-40)

increased steam host demand, and would therefore yield minimal savings from a contract renegotiation. Id.

Staff found the Company's arguments for not accepting the suggested disallowance proposed by the Auditors convincing. With respect to the delay in the closing of the Bayonne PPA restructuring and the Company's rejection of the Reliant proposal, however, Staff agreed that both should be investigated further in Phase II of the audit. Staff also noted that in addition to mitigating NUG costs through buyouts or buydowns of the related PPAs, the Final Restructuring Order directed the Company to maximize the value of NUG contract power either through market sales, or by devoting it to BGS supply:

> GPU [JCP&L] has an ongoing obligation to take all reasonable measures to mitigate the stranded costs associated with NUG utility Purchase Power Agreements, including optimizing the market revenues received for the sale of power and other marketable services derived from the Purchase Power Agreements on the open market, or for use of Non-Utility Generator and Utility Purchase Power Agreement power to offset purchases of energy and capacity or other services otherwise necessary to serve Basic Generation Service customers...
>
> [Final Restructuring Order at 109, paragraph 22]

In view of this requirement, and the possibility that using NUG energy to supply BGS could provide greater value than reselling the NUG energy to PJM,[99] and to monitor and assess the value received from the resale of the NUG energy on an ongoing basis, Staff recommends that in addition to the quarterly reporting requirement previously ordered by the Board, that the Company be directed to file monthly reports that show, for each NUG project, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (i.e., whether it was resold in the wholesale market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rate, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction.

In accepting this recommendation of Staff, as well as its extension to Yards Creek and the Forked River CTs, we incorporated this identical language in the Summary Order (at 16-17). Upon further review, we **HEREBY MODIFY** this directive to 1) add the phrase "for the zone in which JCP&L operates" after "LMP;" and 2) to replace "capacity deficiency rate" with "the average rate at which capacity sales were transacted during the month;" and 3) to replace "rate payable for BGS supply obtained pursuant to the statewide auction" with the "energy and capacity component of the rate payable for BGS supply obtained pursuant to the statewide auction, or if not known precisely, a reasonable estimate thereof." The Company accordingly is directed to implement this

[99] Staff also cited this possibility for the output of Yards Creek and the Forked River CTs.

change going forward, and to provide revised versions of the reports previously supplied in response to the Summary Order to reflect this change.

Additionally, with respect b Yards Creek and the Forked River CTs, we **HEREBY DIRECT** the Company to include, as part of its Phase II filing in this proceeding, an economic study that addresses the "best use" of these facilities for the benefit of ratepayers. Such a study should examine whether the units should be divested or retained, and, as suggested above, if and while retained, there is a more advantageous use of the output of the units than reselling their energy and capacity at wholesale. Also to be included in the study is a proposal for the ratemaking treatment to be accorded the units in the event they were to be retained.

With respect to the Advocate's proposed interest disallowance, and while noting that the Company has been less than aggressive than PSE&G in mitigating the above market costs of it NUG contracts, we, like Staff and the Auditors, do not believe that the Company's efforts warrant the disallowance recommended by the Advocate. We also note that following the restructuring of the Bayonne contract, the Company successfully restructured its PPA with North Jersey Energy Associates for the purchase of energy and capacity from the South River (Sayreville) project with attendant NPV savings estimated to be in excess of $50 million.[100] The Company has also restructured its PPAs with Calpine Newark, LLC and Calpine Parlin, LLC, as well as the agreement for the gas supply for these projects. As a result it received an upfront payment of $52.8 million associated with the re-negotiated PPAs, which is to be credited to the MTC deferred balance, net of reasonably and prudently incurred transaction costs. Additionally, PSE&G is to credit a $22 million payment it received as a result of the renegotiation of the gas contract to the benefit of its gas customers.[101]

Finally, with respect to the small projects, we agree with Staff that the Company appropriately prioritized its mitigation efforts, that these projects appear to involve complicating factors not present with the other projects, and that the resultant savings, if any, would not be significant relative to those potentially achievable from re-negotiating the PPAs with the larger projects. Accordingly, we **HEREBY REJECT** the disallowance suggested by the Auditors.

D. SBC DEFERRED BALANCE/CHARGES

(1) Nuclear Decommissioning Funding

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[100] I/M/O the Application of Jersey Central Power & Light Company for the Approval of an Amendment and Restatement of the Power Purchase Agreement Currently Existing Between it and North Jersey Energy Associates, a Limited Partnership, Docket No. EM03060438, Order dated November 5, 2003.

[101] I/M/O the Application of Jersey Central Power & Light Company for the Approval of the Termination of the Power Purchase Agreements Currently Existing Between it and Calpine Newark, LLC and Calpine Parlin, LLC and the Execution of a New Power Purchase Agreement with CES Marketing II, LLC or its Designee and I/M/O the Application of Public Service Electric and Gas Company for the Approval of an Amendment to the Gas Service Agreement Currently Existing Between it and Jersey Central Power & Light Company Docket No. EM04010045, Order dated March 24, 2004.

In its Reply Brief at 113 the Company accepted Staff's recommended reduction in the carrying costs applicable to the unamortized balance of the Oyster Creek top-off payment to reflect the Board's rate of return finding in the Company's base rate case, and we **HEREBY ORDER** such carrying costs to be so reduced. As indicated in the Summary Order, the reduction amounts to approximately $3.3 million per year. The Company also indicated in its Reply Brief that it had corrected its claimed amortization of the TMI-1 top-off payment to eliminate carrying costs, which were not authorized by the Board's Order approving the TMI-1 sale. Additionally, the Company asserted that its proposed revision in TMI-2 decommissioning funding was simply an update to reflect changes in inflation and earnings rates, and the remaining balance to be amortized. (Id.). On that basis, we **HEREBY APPROVE** the annual amounts shown in Schedule MJF-8 ("12+0" Update) included in Exhibit JC-75 of $2.1 million and $2.9 million for TMI-1 and TMI-2, respectively.

With respect to Saxton, the Company argues, in its Reply Brief, that the fact that the ratepayers of the Company's affiliates in Pennsylvania are no longer funding the cost of decommissioning this facility is not a basis for terminating funding on the part of New Jersey ratepayers. (Id. at 114-115). We disagree, finding no basis for continuing an unbalanced regulatory treatment at the expense of New Jersey ratepayers, an imbalance we find already excessive, as evidenced by the disparity in accumulated funding shown in Exhibit S-6, i.e., a JCP&L Saxton trust fund balance as of December 31, 2002 of $0.5 million as compared to less than $5,000 for the Pennsylvania companies combined. Accordingly, we **HEREBY DISALLOW**

the Board **HEREBY AUTHORIZES** the Company to include $22.0 million of such costs in the SBC.

(3) Demand Side Management (DSM)

JCP&L recovers its regulated DSM costs through the SBC. The Company requests an annual recovery of $38.8 million, resulting in a decrease in its DSM of over $15 million. The RPA did not oppose the Company's request, but did address the Company's request for lost revenues as part of the Company's energy efficiency programs. Staff did not oppose the Company's request.

Based upon the record in this matter, the Board **HEREBY ADOPTS** the Company's proposal to reflect a reduction in the Company's annual recovery of DSM costs, i.e., Clean Energy Program costs, in the amount of $15.0 million.

(4) Consumer Education (CED)

The Company proposes to recover all Board approved costs associated with the CED, along with any carrying charges, beginning August 1, 2003. The Company estimates that the CED costs will total approximately $5.6 million and proposes to recover these costs through a base charge of 0.0278 cents per kwh.

The RPA would disallow any recovery by the Company of its CED costs for Year 2 and Year 3. The RPA believes that the statewide CED failed to achieve its goals of increasing awareness among gas and electric consumers in the critical areas of energy competition, alternate energy suppliers, energy conservation and efficiency, and the availability of financial assistance to eligible consumers.

Staff believes the Company is entitled to recover its costs associated with the CED and agrees with the Company's proposed CED Tariff Rider of 0.0278 cents per kwh.

The Consumer Education program was a statewide effort jointly funded by all of the State's electric and gas utilities. M&T, the Board's independent auditors, audited the CED deferred balance through July 31, 2002 and noted no material non-compliance issues with JCP&L's accounting of the rate recovery or recording of expenses related to this SBC component. The Board **HEREBY ADOPTS** the Company's proposal, as supported by Staff, and **HEREBY APPROVES** JCP&L's recovery of these CED costs.

E. INTERIM RECOVERY OF DEFERRED BALANCES

Staff, the Advocate and the Company all note that while the Board has reserved for decision in the Company's pending securitization proceeding[103] the issues as to whether all or some portion of the Company's deferred balances (i.e., its BGS and MTC balances) should be amortized or securitized, and over what period and at what rate, the Board did not preclude the parties from making proposals for the interim recovery of the balances in this proceeding pending the Board's final decision. Accordingly, based on

[103] The Company's securitization petition in Docket No. ER03020133 was filed on February 14, 2003, and amended on September 19, 2003 to reflect the Board's disallowance of $152.5 million of BGS deferrals. A second amendment was filed on December 1, 2003. Discovery has been issued and responded to, and the Advocate's testimony was filed on January 16, 2004.

the testimony of its witness Rothschild (R-49) the Advocate proposed amortizing the Company's deferred balances over a 10-year period at the rate on 7-year treasury notes plus 60 basis points, the rate previously authorized by the Board on deferrals incurred during the transition period. Moreover, the recovery should be "net of tax." (RIB at 74-79). The Company on the other hand argues for a four-year recovery at the 7-year treasury rate, or alternatively, an amortization period of more than four years but less than ten, with interest at the Company's overall weighted average cost of capital. (CIB at 193) Staff, like the Advocate, proposes net-of-tax recovery over ten years, but at the rate on 1-year treasuries plus 30 basis points. Staff maintains that this rate is appropriate on the expectation that the interim recovery will be in effect for at most a matter of months.

Given the rate impact of four-year recovery (at 12.4%, more than double the 6.1% increase estimated by the Company assuming its requested "12+0" base rate increase

annually, did not reflect the tax benefit from the interest itself during the deferral period, and was calculated on a "simple interest" basis.

With respect to the rate, because the SBC, BGS and MTC charges will now be revised annually, the use of the Company's rate on short-term debt (debt due in one year or less, or if no short-term debt is outstanding, the rate on equivalent temporary cash investments) will more accurately reflect the Company's true cost of borrowings to finance deferrals than would continued use of the 7-year treasury rate. Similarly, the rate on equivalent temporary cash investments appropriately and symmetrically reflects the interest due ratepayers on over-recoveries. We also agree with Staff that it is desirable to standardize the method as well as the rate employed by the Company, Atlantic Electric and RECO,[107] i.e., by calculating interest monthly on the beginning and end average of the balance of deferred costs less the deferred taxes associated with the deferred costs and interest, and by compounding interest annually.[108] Accordingly, we **HEREBY APPROVE** the changes recommended by Staff, and **HEREBY DIRECT** the Company to recalculate the interest accrued on its deferred balances during the transition period to reflect the methodology approved herein, and additionally, to prospectively employ, as the rate applicable to post-transition deferrals, the monthly rate actually incurred on short-term debt, or in the event no short-term debt is outstanding, the rate available on equivalent temporary cash investments.

G. DISCONTINUANCE OF THE MTC AND ITS REPLACEMENT BY THE NGC

Section 13 (C.48:3-61) of the EDECA provides for the imposition of a limited duration, non-bypassable market transition charge for the recovery of generation-related stranded costs, buyouts and buydowns of uneconomic PPAs with other utilities and non-utility generators, and restructuring costs approved by the Board. Unless extended by the Board to recover above-market payments under PPAs with NUGs over the terms of the PPAs, or the costs of a specific generating asset comprising at least 20% of the utility's stranded costs, or to achieve the rate reductions mandated by the EDECA, the term of the MTC is not to exceed eight years. For the Company (as well as the state's other electric utilities), the Board established a four-year period for effecting the transition to a market-based generation supply, and that period is now over. However, the need for an ongoing charge to bill above-market costs associated with NUG PPAs, net of the revenue received from the sale of the NUG energy and capacity in the wholesale power markets, or other employment of the NUG energy and capacity continues. Moreover, at least for now, the generation and the capacity of Yards Creek and the Forked River turbines is also being sold in the wholesale power markets, with the revenue received from such sales, net of the units' revenue requirement, credited to above market NUG costs.

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[107] The PSE&G Settlement approved by the Board provided for a similar change in post-transition interest accruals.

[108] As illustrated in Exhibit 2 attached to the Board's Final Order issued on April 20, 2004 in the deferred balances and base rate proceedings of Rockland Electric Company (I/M/O the Verified Petition of Rockland Electric Company for the Recovery of its Deferred Balances and the Establishment of Non-Delivery Rates Effective August 1, 2003 (Docket No. ER02080614) and I/M/O the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, its Tariff for Electric Service, its Depreciation Rates and for Other Relief (Docket No. ER02100724).

While this treatment could presumably continue for another four years, i.e., if the Board were to authorize a continuation of the Company's MTC as currently constituted for another four years, and if Yards Creek and the Forked River turbines were to be retained that long, the EDECA would not appear to allow the inclusion of these units in an MTC beyond then. Moreover, with the transition period now over, the basis for calling this unbundled rate charge an MTC, i.e., a "market transition charge," no longer applies. Accordingly, we believe it appropriate to discontinue the MTC, and replace it with a non-utility generation charge ("NGC") for the continued recovery of above-market NUG costs, net of the revenue received from the sale of the energy and capacity of the NUGs, and, pending review of this treatment in Phase II of this proceeding, the net revenue requirement of the Company's retained generating units, effective upon the date the Company's unbundled rates (i.e., its unbundled rates other than its distribution charges) are next changed.

VII. SUMMARY OF BOARD FINDINGS, DEFERRED BALANCES

(a) Deferred BGS/MTC Balance

1. After deducting the disallowance of deferred BGS costs of $152.5 million ordered herein from the Company's deferred BGS/MTC balance of $618.0 million projected as of July 31, 2003, including accrued interest of $40.7 million, the Company is **HEREBY AUTHORIZED** to recover a deferred BGS/MTC balance of $465.5 million.

2. This balance shall be trued-up to reflect: 1) actual data through July 31, 2003; 2) the results of the Board-ordered Phase II Audit of the Company's deferred balances; 3) the reduced return on the Company's generating units accrued during the transition period, as directed below; and 4) a re-calculation of accrued interest to reflect the disallowance and these adjustments, as well as the change in the interest rate calculation methodology, also as directed below.

3. For purposes of interim recovery pending the Board's decision on the Company's securitization petition, the recoverable BGS/MTC balance shall be recovered at the rate of $48.541 million per year before application of the 6% New Jersey Sales and Use Tax, and $51.453 million per year with the tax included.

4. With the exception of Oyster Creek, for purposes of determining the revenue requirement of the Company's generating units during the period the energy and capacity of the units was devoted to BGS supply, and the revenue requirement included as part of the costs recoverable by the shopping credit and the MTC, the return component of the revenue requirement shall be recalculated to reflect an overall rate of return of 9.50%, as well as accumulated depreciation from monthly depreciation of the units, as described herein. For Yards Creek and the Forked River CTs, the return component of the revenue requirement shall additionally

6. The issues of the delayed receipt of the $25.4 million upfront payment from the Bayonne NUG project and why the Reliant Energy NUG PPA restructuring proposal was turned down will continue to be pursued in the Phase II Audit.

7. As part of its Phase II filing in this proceeding, the Company shall include an economic study that, given current and projected conditions in the energy markets, addresses 1) whether it is likely to be better for ratepayers if the Company's interest in Yards Creek and the Forked River CTs are retained or divested; 2) the most economic use of these units while retained (i.e., whether the energy and capacity of the units should be sold in the wholesale power markets or devoted to BGS supply); and 3) the ratemaking treatment to be accorded the units while they are retained. The effect of retaining or divesting the units on the Company shall also be addressed in the study.

8. Effective on the date the Company's non-distribution unbundled rates are next changed, the MTC shall be discontinued and renamed the NGC, which charge shall continue to recover the above-market component of payments made under PPAs with non-utility generators (the PPA payments less the revenue received from the sale of the NUG energy and capacity), as well as the revenue requirement of Yards Creek and the Forked River CTs, net of the revenue received from the sale of the capacity and energy from these units, while they are retained.

(b) SBC Deferred Balance/Charges

1. Subject to the Phase II Audit of the Company's deferred balances, the Board **HEREBY APPROVES** the Company's proposed changes in its charges for DSM/Clean Energy program costs (a reduction of $15.0 million), and Consumer Education (CEP) costs (an increase of $5.6 million).

2. Pursuant to the Board's July Order in Docket No. EX0002009, I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999, the Board **HEREBY AUTHORIZES** the Company to include $22.0 million of USF costs in the SBC.

3. With respect to the nuclear decommissioning component of the SBC, the Board 1) **HEREBY DISALLOWS** the $0.6 million of annual funding claimed by the Company for Saxton; 2) **HEREBY APPROVES** the Company's proposed reduction in the recovery of the TMI-1 top-off payment from $5.2 million to $2.1 million per year, without carrying costs, through August 2009; 3) **HEREBY APPROVES** a reduction in the Oyster Creek top-off payment from $18.2 million to $14.9 million per year through August 2009 to reflect the rate of return allowed in this proceeding, and 4) **HEREBY APPROVES** decommissioning funding of $2.9 million per year for TMI-2, pending a further review of the justification for continuing this level of funding and other TMI-2

decommissioning issues in Docket No. EO03121014, I/M/O the Request of Jersey Central Power & Light Company for a Waiver of Filing Requirements under N.J.A.C. 14:5A, Nuclear Plant Decommissioning Cost and Trust Fund Review.

(c) Interest Calculation

1. The Board **HEREBY DIRECTS** the Company to re-calculate its interest accruals during the transition period to reflect 1) the deduction of deferred income taxes associated with deferred interest as well as the deferred income taxes associated with the deferred costs from the balance on which interest is accrued; 2) a monthly calculation based on the beginning and end average monthly balance, as opposed to an annual calculation; and 3) annual compounding.

2. For post-transition deferrals, i.e., effective August 1, 2003, the method of calculating interest on the Company's BGS, SBC and MTC/NGC deferrals shall be as described in 1) above, but the interest rate shall be reduced from the yield on constant maturity 7-year treasury notes plus 60 basis points to the average rate on the Company's short-term debt outstanding (debt due in one year or less), or in the event that no short-term debt is outstanding, to the rate on equivalent temporary cash investments

[redacted]

1. The Board **HEREBY APPROVES** continued use of deferred accounting for under and over recoveries of costs recoverable by the SBC and MTC/NGC, as well as for under and over recoveries of costs incurred in supplying BGS, all of which such under and over recoveries shall be recorded as regulatory assets and liabilities on the balance sheet.

VIII. EFFECT OF ALL RATE CHANGES

In addition to reflecting the base rate reduction, the interim recovery of the deferred BGS/MTC balance, the revised components of the SBC, as well as the expiration of the Year 4 EDECA rate reduction, all as provided herein, the Company will implement an increase in its BGS charges effective August 1, 2003 to reflect the results of the

For the typical residential customer using 686 kwh per month during the winter and 952 kwh per month during the summer, the provisions of this Final Order result in an average annual increase in rates of approximately 3.5% (from approximately $86.01 per month to approximately $89.07 per month).

DATED: ***MAY 17, 2004***

BOARD OF PUBLIC UTILITIES
BY:

SIGNED

JEANNE M. FOX
PRESIDENT

SIGNED

FREDERICK F. BUTLER
COMMISSIONER

SIGNED

CAROL J. MURPHY
COMMISSIONER

SIGNED

CONNIE O. HUGHES
COMMISSIONER

SIGNED

JACK ALTER
COMMISSIONER

ATTEST:

SIGNED

KRISTI IZZO
SECRETARY

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-1*
Additional Revenues to Achieve Return
($1,000)

Line No.		Petitioner	adjustment	Ratepayer Advocate	adjustment	Staff	adjustment
1	Rate Base	2,053,575	(138,700)	1,914,875	(37,276)	2,016,299	(37,276)
2	Rate of Return	10.05%	-1.97%	8.08%	-1.55%	8.50%	-1.67%
3	Required Operating Income	206,384	(51,662)	154,722	(34,999)	171,385	(37,418)
4	Pro Forma Operating Income	230,928	72,296	303,224	69,682	300,610	69,507
5	Income Deficiency	(24,544)	(123,958)	(148,502)	(104,681)	(129,225)	(106,925)
6	Revenue Factor	1.69062	0.00336	1.69398	0.00336	1.69398	0.00336
7	Revenue Deficiency	(41,494)	(210,065)	(251,560)	(177,410)	(218,904)	(181,212)
8	Applicable Taxes on Revenue Deficiency:						
9	Taxes Other Than Income (Line 7 x Effective Tax Rate of 0.00%)	0					
10	State ((Line 7 - Line 9) x Effective Tax Rate of 9%)	($3,734)					
11	Federal (((Line 7-Line 9)-Line 10) x Effective Tax Rate of 35%)	(13,216)					
12	Total Taxes on Revenue Deficiency	(16,950)					
13	Effect on Operating Income	(24,544)					

***Differences due to rounding.**

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-2
Rate Base @ 12/31/2002
($1,000)

Line No.		Petitioner	adjustments	Ratepayer Advocate	adjustments	Staff	adjustments	Board
1	Total Electric Utility Plant in Service	3,397,395	0	3,397,395	0	3,397,395	0	3,397,395
	Additions:							
2	Deferred Taxes --TMI -2 Non-Qualified Decommissioning Trust Fund	11,314	0	11,314	0	11,314	0	11,314
3	Total Additions	3,408,709	0	3,408,709	0	3,408,709	0	3,408,709
	Deductions:							
4	Accumulated Deferred Income Taxes	261,874	0	261,874	0	261,874	0	261,874
5	Accumulated Provision for Depreciation	1,319,563	0	1,319,563	0	1,319,563	0	1,319,563
6	Customer Advances for Construction (Net of Tax)	7,017	0	7,017	0	7,017	0	7,017
7	Unamortized Net Gain/(Loss) on Reacquired Debt	(17,366)	0	(17,366)	0	(17,366)	0	(17,366)
8	Customer Deposits	16,745	0	16,745	0	16,745	0	16,745
9	Operating Reserves (Net of Tax)	8,597	0	8,597	0	8,597	0	8,597
10	Total Deductions	1,596,430	0	1,596,430	0	1,596,430	0	1,596,430
11	Net Investment	1,812,279	0	1,812,279	0	1,812,279	0	1,812,279
12	Working Capital:							
13	Materials & Supplies -- Other than Fuel	22,703	0	22,703	0	22,703	0	22,703
14	Cash Working Capital	218,593	(77,560)	141,033	(376)	218,217	(376)	218,217
15	Total Working Capital	241,296	(77,560)	163,736	(376)	240,920	0	240,920
16	Consolidated Tax Savings	0	(61,140)	(61,140)	(36,900)	(36,900)	(36,900)	(36,900)
17	Net Rate Base	2,053,575	(138,700)	1,914,875	(37,276)	2,016,299	(37,276)	2,016,299

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DOCKET NO. 04-0113
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Schedule Board-3a
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

	Petitioner				
	Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
ribution (Inc. TEFA)	872,775	(12,382)	860,393	(41,494)	818,899
	27,838	0	27,838	0	27,838
	900,613	(12,382)	888,231	(41,494)	846,737
Exp. Including Labor	226,724	91,380	318,104	0	318,104
	145,523	1,751	147,274	0	147,274
	0	0	0	0	0
s	0	0	0	0	0
ıs	56,049	8,915	64,964	0	0
	428,296	102,046	530,342	0	465,378
e Taxes	472,317	(114,428)	357,889	(41,494)	381,359
	36,507	(23,769)	12,738	(13,216)	(478)
	8,378	(6,717)	1,661	(3,734)	(2,073)
	116,113	0	116,113	0	116,113
	0	0	0	0	0
	(3,550)	0	(3,550)	0	(3,550)
	157,448	(30,486)	126,962	(16,950)	110,012
	314,869	(83,942)	230,927	(24,544)	206,383

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3b
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Ratepayer Advocate

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	5,405	865,798
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	5,405	893,636
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	(61,371)	256,733
6	Depreciation and Amortization	145,523	1,751	147,274	(39,398)	107,876
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	(8,812)	56,152
10	**Total Operating Expenses**	428,296	102,046	530,342	(109,581)	420,761
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	114,986	472,875
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	33,284	46,022
14	State	8,378	(6,717)	1,661	9,405	11,066
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	42,689	169,651
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	72,297	303,224

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3c
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Pro Forma Present Rates	Staff Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	5,405	865,798
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	5,405	893,636
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	52,446	370,550
6	Depreciation and Amortization	145,523	1,751	147,274	(39,398)	107,876
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	(8,812)	56,152
10	**Total Operating Expenses**	428,296	102,046	530,342	(100,656)	534,578
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	106,061	359,058
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	28,363	41,101
14	State	8,378	(6,717)	1,661	8,015	9,676
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	36,378	163,340
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	69,683	300,610

Jersey Central Power and Light Company
BPU Docket No. ER02080506
OAL Docket No. PUC7984-02

Schedule Board-3d
Statement of Pro Forma Operating Income for the Twelve Months Ended 12/31/2002
Normalized and Adjusted to Reflect the Effect of Known and Major Changes and Proposed Rates
($1,000)

Line No.		Actual Ended 12/31/02 Delivery T&D	Normalization Adjustments	Board Pro Forma Present Rates	Additional Revenues to Achieve Return	Pro Forma Proposed Rates
1	Operating Revenues:					
2	Delivery - Transmission & Distribution (Inc. TEFA)	872,775	(12,382)	860,393	5,405	865,798
3	Other Operating	27,838	0	27,838	0	27,838
4	**Total Revenue**	900,613	(12,382)	888,231	5,405	893,636
5	Total Operating & Maintenance Exp. Including Labor	226,724	91,380	318,104	(52,271)	265,833
6	Depreciation and Amortization	145,523	1,751	147,274	(39,398)	107,876
7	Decommissioning	0	0	0	0	0
8	Amortization of Property Taxes	0	0	0	0	0
9	Taxes other than Income Taxes	56,049	8,915	64,964	(8,812)	56,152
10	**Total Operating Expenses**	428,296	102,046	530,342	(100,481)	429,861
11	Operating Income Before Income Taxes	472,317	(114,428)	357,889	105,886	463,775
12	Income Taxes:					
13	Federal	36,507	(23,769)	12,738	28,363	41,101
14	State	8,378	(6,717)	1,661	8,015	9,676
15	Deferred Income Taxes (Net)	116,113	0	116,113	0	116,113
16	Investment Tax Credit	0	0	0	0	0
17	Amortization of ITC	(3,550)	0	(3,550)	0	(3,550)
18	**Total Income Taxes**	157,448	(30,486)	126,962	36,378	163,340
19	**Net Utility Operating Income**	314,869	(83,942)	230,927	69,508	300,435

Board
2,016,299
8.38%
168,966
300,435
(131,469)
1.69398
(222,706)

EXHIBIT 1

JERSEY CENTRAL POWER & LIGHT COMPANY
Cost of BGS Supply by Sources *
3 Years Ended July 31, 2002

	$ Millions	% of Total
Owned Generation Prior to Divestiture **	$ 243	7.9%
Power Purchases:		
TPPAs (TMI-1, Oyster Creek and Sithe)	558	18.2
PJM Spot Market	438	14.3
Two-Party and Bilateral Contracts	1,155	37.6
Utility PPAs at Market ***	15	0.5
NUG PPAs at Market ***	550	17.9
Ancillary Services	98	3.2
Financial Instruments	14	0.4
Total	2, 828	92.1
Total Cost of BGS Supply	$3,071	100.0%
Per Mwh of Net System Requirements	$50.15	
Revenue		
Shopping Credit	$2,498	
Sales for Resale	282	
Total	$2,780	
BGS Deferred Balance at 7/31/02	$291	
Projected Balance as of 7/31/03	$369	

* from Schedule SDM-1A, Exhibit JC-13 ("12+0" Update). Excludes return on and of Oyster Creek investment (treated as a stranded cost).

** includes Yard Creek and the Forked River Combustion Turbines ("CTs") throughout the period (these units were not divested).

*** valued at the average PJM Locational Marginal Price ("LMP") and capacity rate; above market component included in the MTC.

EXHIBIT 2
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JERSEY CENTRAL POWER & LIGHT COMPANY
BGS Disallowance, Discretionary Purchases other Than TPPAs
Three Years Ended July 31, 2002

	Gwh or Avg. Mw	$ Millions	$ per Mwh or Mw-Day	% Incr.
Actual Cost of Discretionary Purchases Other than TPPAs:				
Energy	18,735	$ 974.1	$ 51.99	
Capacity	1,813	151.1	105.35	
Total		1,125.2	60.06	
Cost if Purchased from PJM:				
Energy	18,735	699.9	37.36	
Capacity	1,813	96.3	67.18	
Total		796.2	42.50	
Cost above PJM:				
Energy		274.2	14.63	39.2%
Capacity		54.8	38.17	56.9
Total		$ 329.0	$ 17.56	41.3%
TPPA and Other Offsets:				
TMI-1 TPPA				
Energy (3,205 Gwh x ($38.12/Mwh - $27.52/Mwh))		$ (34.0)		
Capacity (196 Mw x 743 days x $82.26/Mw-Day)		(12.0)		
Oyster Creek TPPA				
Energy (9,708 Gwh x ($38.99/Mwh - $35.29/Mwh))		(35.9)		
Capacity (619 Mw x 723 days x $63.22/Mw-Day)		(28.3)		
Additional Oyster Creek savings, Year 4				
Energy (3,232 Gwh x ($39.23/Mwh - $33.19/Mwh))		(19.5)		
Cap. (imputed; 619 Mw x 243 days x $56.92/Mw-Day)		(8.6)		
TMI-1 "Deal Strike Price Adjustments" (NPV)		(12.8)		
Bayonne NUG restructuring		(25.4)		
Disallowance		$152.5		

EXHIBIT 2
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SOURCES:

Exhibit S-32 (Company's response to S-JBGS-1), cost comparison, actual cost of discretionary purchases versus cost if purchased at "Sink Bus LMP" and "Weighted Average PJM Capacity Rate."

Exhibit S-36 (Company's response to S-RD-32), TMI-1, Oyster Creek and Sithe TTPA purchases and cost data.

Exhibit S-52 (Company's response to S-JMTC-2, incl. supplemental), year 4 Oyster Creek TPPA purchases and cost data for period August 2002 through March 2003.

Exhibit S-53 (Company's response to S-JMTC-3), TMI-1 "Deal Strike Price Adjustments"

- Discretionary purchases other than TPPAs exclude long-term (pre-transition period) PPAs with other utilities and NUGs.

- In determining the savings from the TMI-1 and Oyster Creek TPPAs relative to PJM, the average cost of each TPPA over the period it was in effect from Exhibit S-36 was compared to the average cost of the same energy and capacity (unadjusted for the underlying unit's forced outage rate) if purchased from PJM over the same period from Exhibit S-32.

- While the same analysis indicates the Sithe TPPA was about $28.1 million more expensive than purchasing the same capacity from PJM during the period the Sithe TPPA was in effect (November 7, 1999 through May 31, 2002; $28.1 million = 1,604 Mw x 937 days x ($67.18 - $85.90)), the Board's approval of the Sithe TPPA was not conditioned on a prudency review. Any such review would have to take into account a possible offset from the favorable effect a capacity only TPPA may have had on the sale price received for the divested fossil units. No adjustment was therefore made.

- The additional Oyster Creek energy savings in Year 4 of the Transition Period were taken directly from Exhibit S-47. The imputed capacity value was determined by pricing the Oyster Creek Mw-days at the average price paid for capacity during the period August 2001 through March 2002, from Exhibit S-32.

EXHIBIT 3

JERSEY CENTRAL POWER & LIGHT

DOCKET NO. ER02080506

Capital Structure and Weighted Average Cost of Capital

	Percentage Of Total	Cost Rate	WACC*
Long-Term Debt	47.77%	7.26%	3.47%
Tax Deductible Preferred	5.66%	9.24%	0.52%
Preferred Stock	0.57%	4.01%	0.02%
Common Equity	46.00%	9.50%	4.37%
	100.00%		8.38%

* Weighted Average Cost of Capital

Jersey Central Power & Light Company

Schedule S-Rev-4

Consolidated Tax Savings - Staff's Adjustment

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative	
JCP&L Taxable Inc/(Loss)	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718		2,330,642,741	41.05%
Total Positive-Affiliate Taxable Income (1)	401,768,218	374,341,945	319,798,551	357,845,285	430,160,000	416,844,661	682,841,263	831,330,238	1,862,587,526		5,677,517,687	
Total Negative-Affiliate Taxable (Loss) (2)	(8,349,047)	(5,581,722)	(4,004,836)	(6,735,441)	(11,128,477)	(45,696,268)	(24,267,728)	(82,134,933)	(68,927,347)			
Statuatory Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%			
Consolidated Tax Savings	(2,922,166)	(1,953,603)	(1,401,693)	(2,357,404)	(3,894,967)	(15,993,694)	(8,493,705)	(28,747,227)	(24,124,571)			
Alternative Minimum Tax	0	0	0	0	0	0	0	0	0			
Total Net Savings	(2,922,166)	(1,953,603)	(1,401,693)	(2,357,404)	(3,894,967)	(15,993,694)	(8,493,705)	(28,747,227)	(24,124,571)		(89,889,030)	
JCP&L's % of Positive Affil. Tax Inc.											41.05%	
Tax Benefit - JCP&L											(36,899,791)	

Consolidated Tax Savings - RPA's Adjustment

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
JCP&L Taxable Inc/(Loss)	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718		
Total Positive Taxable Income (3)	404,274,324	375,228,895	324,843,082	366,080,154	457,168,143	422,538,127	705,057,362	867,830,114	1,902,106,134		
JCP&L's % of Positive Taxable Inc.	42.21%	27.22%	39.47%	38.80%	65.63%	50.29%	55.61%	46.16%	25.36%		
Non-Reg Tax Losses (4)	(10,839,085)	(6,452,100)	(9,035,847)	(14,965,129)	(38,134,625)	(51,387,738)	(46,481,830)	(118,632,811)	(108,443,956)		
JCP&L's share of tax loss	(4,575,224)	(1,756,505)	(3,566,898)	(5,806,510)	(25,027,150)	(25,845,106)	(25,847,868)	(54,764,255)	(27,499,540)		
Statuatory Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%		
Tax Benefit - JCP&L	(1,601,328)	(614,777)	(1,248,414)	(2,032,278)	(8,759,503)	(9,045,787)	(9,046,754)	(19,167,489)	(9,624,839)		(61,141,170)

(1) Sum of taxable income / (loss) during the year from affiliates with postive cumlative taxable income for the cumulative period.
(2) Sum of taxable income / (loss) during the year from affiliates with negative cumlative taxable income for the cumulative period.
(3) Sum of taxable income / (loss) during the year from affiliates with postive taxable income during the year.
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Jersey Central Power & Light Company

Schedule S-Rev-4

Source Data

		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
Taxable Income /(Loss)												
	GPU, INC	(8,573,603)	(5,366,331)	(5,353,912)	(7,492,157)	(10,073,498)	(13,960,300)	(13,920,986)	(10,944,568)	(17,818,371)	(35,354,999)	(128,858,725)
	GPU Service Inc.	2,109,204	2,341,317	(2,151,132)	3,503,133	(10,129,538)	7,397,036	11,302,090	3,349,440	18,149,315	(30,546,572)	5,324,293
	GPU Nuclear Inc.	2,991,825	5,021,155	1,819,718	15,643,718	(8,735,804)	9,672,626	4,698,916	4,587,005	417,193	13,343,164	49,359,516
	General Portfolio Corp.	(3,876)	(28,632)	204,300	0	0	0	0	0	0	0	171,792
R	Jersey Central Power & Light	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718	(278,586,515)	2,052,056,226
	JCPL Preferred Capital Inc.					193,262	1,421,957	1,502,217	1,615,606	1,672,873	1,688,555	8,094,470
	JCP&L Transition Inc.											0
	JCP&L Transition Holdings, Inc.											0
R	Metropolitan Edison Company	108,327,927	136,587,635	76,544,327	101,042,076	58,917,038	79,799,331	114,844,648	134,271,091	284,481,894	73,631,926	1,168,447,893
R	York Haven Power company	878,943	1,157,474	924,231	1,493,420	1,344,614	1,567,697	1,468,891	1,802,464	262,308	2,656,844	13,556,886
	Met-Ed Preferred Capital II Inc.									(11,858)	76,487	64,629
	Met-Ed Preferred Capital Inc.				87,103	195,395	1,168,906	1,261,784	1,363,965	1,070,932		5,148,085
R	Pennsylvania Electric Company	119,024,939	126,902,324	115,027,767	100,453,375	85,732,013	80,414,051	130,299,927	122,568,265	1,029,842,923	46,286,405	1,956,551,989
R	NinevehWater Company	(14,077)	(14,580)	(11,527)	(3,187)	293	10,616	14,774	12,738	4,800		(150)
	Penelec Preferred Capital II Inc.									(11,576)	(16,622)	(28,198)
R	Waverly Electric Light & Power											0
	Penelec Preferred Capital Inc.									574,767		574,767
R	Saxton Nuclear Experimental Corp.				115,230	199,056	1,239,422	1,330,350	1,440,129			4,324,187
	GPU Advanced Resources Inc.									(6,835,751)	(2,744,851)	(9,580,602)
	GPU Telcom Services Inc.						(519)	(6,470,485)	(4,565,704)	5,532,913	18,532,584	13,028,789
	GPU Diversified Holdings, Inc.						(519)	(102,284)	3,896,491			3,793,688
	GPU Enertech Holdings, Inc.										310,714	310,714
	GPU Genco						21,911,274	(346,800)	2,516,337	(3,514,647)		20,566,164
	GPU Power, Inc.					(3,138)	(644,512)	(1,258,007)	(2,627,982)	(404,190)		(4,937,829)
	Hanover Energy corporation										(2,528,321)	(2,528,321)
	Guaracachi America, Inc.					(68,999)	234,205	1,264,873	(1,531,393)	2,890,870	(1,022,180)	1,767,376
	El Barranquilla, Inc.					(4,187)	(267,066)	(385,209)	(1,302,467)	4,856,092	(758,237)	2,138,926
	Barranquilla Lease Holding, Inc.						102,775	1,142,313	2,839,265	5,046,828	5,251,400	14,382,581
	International Power Advisors, Inc.								166,666	1,611,462	1,670,014	3,448,142
	Austin Cogeneration Corp.											0
	GPU Power Philippines, Inc.											0
	GPU International Asia, Inc.							(148,349)	(191,178)	(398,552)	(35,587)	(773,666)
	GPU Power Ireland Inc.											0
	NCP Energy, Inc.										(87,385)	(87,385)
	NCP ADA Power, Inc.										(131)	(131)
	NCP Brooklyn Power, Inc.											0
	NCP New York, Inc.											0
	GPU Capital Inc.								(157,533)	(43,769,520)	(63,270,218)	(107,197,271)
	GPU electric, Inc.					(471,158)	(1,347,849)	(420)	(4,244,448)	(2,446,920)	(8,024,287)	(16,535,082)
	Victoria Electric, Inc.					(1,146,582)	(397,611)	6,575,248	51,987,015	8,471,168	(2,347,447)	63,141,791
	Victoria electric Holdings, Inc.						(2,116,000)	(4,617,981)	(17,126,221)	(7,061,424)	(6,326,384)	(37,248,010)
	GPU Australia Holdings, Inc.							(2,521,004)	(10,028,400)	(4,948,965)	(57,080,983)	(74,579,352)
	Austran Holdings, Inc.							(16,240,987)	(7,647,159)	(14,151,626)	(274,539,470)	(312,579,242)
	E.I. UK Holdings, Inc.						(20,195,409)	11,913,298	(31,010,792)	26,961,303	8,314,742	(4,016,858)
	GPU Brasil, Inc.											0
	VicGas Holdings, Inc.										(450,080)	(450,080)
	GPU Argentina Holdings, Inc.									1,185,603	3,433,255	4,618,858
	MYR Group, Inc.											0
	Comtel Technology Inc.										(491,136)	(491,136)
	D.W. Close Company, Inc.										(1,185,637)	(1,185,637)
	Great Southwestern Construction										1,018,378	1,018,378
	Harlan Electric Company										4,637,411	4,637,411
	Hawkeye Construction, Inc.										(60,259)	(60,259)

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Jersey Central Power & Light Company

Source Data (Continued)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
MYR Com, Inc.										(1,434,650)	(1,434,650)
MYR Group, Inc.										(14,893,860)	(14,893,860)
MYR Power, Inc										1,645,764	1,645,764
Power Piping Co.										(703,412)	(703,412)
Sturgeon Electric co.										9,913,046	9,913,046
The LE. Myers Co.										12,431,757	12,431,757
GPU International (form. Energyinit.)	(2,206,056)	(707,936)	(1,530,803)	(4,209,307)	9,339,458	2,199,640	13,324,685	(25,453,166)	13,513,312	(3,771,461)	498,366
Elmwood Energy Corporation	288,581	(178,060)	1,156,550	1,290,388	234,693	149,329	1,690,545	3,571,540	1,200,132	(13,776,740)	(4,373,042)
Camichino energy Energy Corp.	(45,956)	(22,751)	204,053	159,309	3,654	(6,587,365)	166,324	(27,805)	2,606,924		(3,543,613)
Geddes cogeneration Corp.	(5,602)	(148,390)	728,412	(609,642)	(2,761,618)	(2,176,732)	5,025,772	112,526,533	2,391,355	8,601,903	123,571,991
Geddes II Corporation									141,367	7,484,956	7,626,323
El Selkirk, Inc.					(657,300)	604,575	879,061	3,074,991	3,366,260	79,193,564	86,461,151
El Fuels Corporation								156,895	521,030	377,242	1,055,167
El Services, Inc								(60,392)	425,156	372,187	736,951
NCP ADA Power, Inc.				29,052	181,000	40,669	(2,717)	(478)			247,526
NCP Energy, Inc.				110,102	758,979	405,849	37,617	9,620,574	(2,687,811)		8,245,310
NCP Commerce, Inc				(793,018)	(501,655)	(573,315)	1,076,733				(791,255)
NCP Lake Power, Inc.				9,370	34,483	(3,501)	(23,036)	(130,875)	(100,364)	(227,398)	(441,321)
NCP Gem, Inc.				201,814	(230,639)	(334,866)	(443,565)	(1,556,414)	(1,647,829)	(20,614,238)	(24,625,737)
NCP Dade Power, Inc.				(107,960)	(121,512)	(93,096)	44,933	(25,836)	(105,418)	369,644	(39,245)
NCP Pasco, Inc.				(1,753,045)	(3,228,997)	(2,689,078)	2,752,193	4,345,498	2,563,637	35,221,126	37,211,334
NCP Perry, Inc.						76,531	268,702	1,129,187	(1,127,037)	5,055,425	5,402,808
NCP Houston Power, Inc.						1,607,028	97,349	371,538	(1,167,550)	2,653,680	3,562,045
Northeast Energy Corp.	4,998	1,065,521									1,070,519
Northeast Cogen, Inc	(3,992)										(3,992)
GPU Generation Serv.-Pasco									(234,547)	459,480	224,933
Total Taxable Income (Loss)	393,419,171	368,760,223	315,793,715	351,109,844	419,031,523	371,148,393	658,573,535	749,195,305	1,793,660,179	(476,247,407)	4,944,444,481
Total Tax Per Return	133,510,076	125,305,806	110,933,884	123,244,327	147,291,629	123,790,841	204,610,179	223,031,043	604,371,203	47,444	1,796,136,432

Source Data Calculations

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Cumulative
Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	
Taxable Income X Tax Rate	137,696,710	129,066,078	110,527,800	122,888,445	146,661,033	129,901,938	230,500,737	262,218,357	627,781,063	(166,686,592)	
Unspecified Adjustment	4,186,634	3,760,272	(406,084)	(355,882)	(630,596)	6,111,097	25,890,558	39,187,314	23,409,860	(166,734,036)	
sum where cumulative is positive	401,768,218	374,341,945	319,798,551	357,845,285	430,160,000	416,844,661	682,841,263	831,330,238	1,862,587,526	18,914,855	5,696,432,542
sum where cumulative is negative	(8,349,047)	(5,581,722)	(4,004,836)	(6,735,441)	(11,128,477)	(45,696,268)	(24,267,728)	(82,134,933)	(68,927,347)	(495,162,262)	
sum where number is positive	404,274,324	375,228,895	324,843,082	366,080,154	457,168,143	422,538,127	705,057,362	867,830,114	1,902,106,134	344,633,653	
sum where number is negative	(10,853,162)	(6,466,680)	(9,047,374)	(14,968,316)	(38,134,625)	(51,387,738)	(46,481,830)	(118,632,811)	(108,443,956)	(820,879,060)	
sum of non-reg where number is negative	(10,839,085)	(6,452,100)	(9,035,847)	(14,965,129)	(38,134,625)	(51,387,738)	(46,481,830)	(118,632,811)	(108,443,956)	(542,292,545)	
JCP&L's % of Positive Regulated	42.78%	27.85%	39.98%	41.15%	67.24%	56.59%	61.26%	60.63%	26.84%	-227.28%	

Regulated Utility Data

		1,991	1,992	1,993	1,994	1,995	1,996	1,997	1,998	1,999	2,000	Cumulative	
R	Jersey Central Power & Light	170,645,916	102,151,477	128,231,731	142,040,070	300,032,210	212,512,614	392,072,122	400,614,883	482,341,718	(278,586,515)	2,052,056,226	39.50%
R	Metropolitan Edison Company	108,327,927	136,587,635	76,544,327	101,042,076	58,917,038	79,799,331	114,844,648	134,271,091	284,481,894	73,631,926	1,168,447,893	22.49%
R	York Haven Power company	878,943	1,157,474	924,231	1,493,420	1,344,614	1,567,697	1,468,891	1,802,464	262,308	2,656,844	13,556,886	0.26%
R	Pennsylvania Electric Company	119,024,939	126,902,324	115,027,767	100,453,375	85,732,013	80,414,051	130,299,927	122,568,265	1,029,842,923	46,286,405	1,956,551,989	37.66%
R	NinevehWater Company	(14,077)	(14,580)	(11,527)	(3,187)	293	10,616	14,774	12,738	4,800	0	(150)	0.00%
R	Waverly Electric Light & Power	0	0	0	0	0	0	0	0	0	0	0	0.00%
R	Saxton Nuclear Experimental Corp.	0	0	0	115,230	199,056	1,239,422	1,330,350	1,440,129	0	0	4,324,187	0.08%
	Regulated Income	398,877,725	366,798,910	320,728,056	345,144,171	446,225,224	375,543,731	640,030,712	660,709,570	1,796,933,643	122,575,175		
	Regulated (Losses)	(14,077)	(14,580)	(11,527)	(3,187)	0	0	0	0	0	(278,586,515)		
	Total Regulated	398,863,648	366,784,330	320,716,529	345,140,984	446,225,224	375,543,731	640,030,712	660,709,570	1,796,933,643	(156,011,340)	5,194,937,031	100.00%

Source: Source Data & Regulated Utility Data = RAR-RR-75
Staturatory Tax Rate = R-38, Exhibit (DEP-1), Schedule 2, Page 3

JG: 7/6/2004 - 10:57 AM