Q. IS COST CAUSATION AN ACCEPTED PRACTICE?

A. Yes. The Board has stated:

> The primary criterion in developing the cost allocation methodology is to follow sound cost causality. Secondary considerations include the availability and reliability of the data to support the exercise, as well as concerns of materiality, practicability and consistency.
>
> The key objective of the cost allocation is to allocate costs among classifications appropriately reflecting cost causality. This objective is furthered by separating distribution assets into bulk, primary and secondary functions.[13]

Q. WHAT DO THE RESULTS IN SCHEDULE JP-11 DEMONSTRATE?

A. Table 9 below shows the revenue requirement and the revenue-to-cost ratios at present rates under the Two Large Use Classes/Direct Assignment study. The corresponding information from Energy+'s Settlement CCOSS is also shown for comparison purposes.

Table 9
Summary of TMMC's Recommended and Energy+'s Settlement CCOSS Results[14]

Customer Class	Revenue Requirement ($000)		Revenue-To-Cost Ratio at Current Rates	
	TMMC	Energy+	TMMC	Energy+
Residential	$22,785.6	$22,646.9	84.9%	85.4%
GS < 50 kW	$4,166.6	$4,104.4	107.1%	108.7%
GS: 50 – 999 kW	$5,839.7	$5,633.4	135.4%	140.3%
GS: 1,000 – 4,999 kW	$2,118.7	$2,012.7	108.0%	113.5%
Large Use	N/A	$1,108.3	N/A	100.7%
Large Use 1	$206.1	N/A	133.8%	N/A
TMMC (Large Use 2)	$391.9	N/A	212.2%	N/A

[13] *Id.* at 3 and 35.

[14] TMMC **Schedule JP-11**; Energy+ Settlement CCOSS, Rows 40 and 75.

Table 9
Summary of TMMC's Recommended and Energy+'s Settlement CCOSS Results[14]

Customer Class	Revenue Requirement ($000)		Revenue-To-Cost Ratio at Current Rates	
	TMMC	Energy+	TMMC	Energy+
Street Light	$493.1	$494.7	151.2%	150.8%
Sentinel	$23.2	$23.4	70.1%	69.6%
Unmetered Load	$78.1	$78.3	90.0%	89.7%
Hydro One 1 CND	$43.5	$43.4	120.7%	120.9%
Waterloo No. CND	$157.9	$157.9	144.9%	144.8%
Hydro One BCP	$29.5	$30.5	401.3%	401.4%
Brantford Power	$12.9	$12.9	44.6%	44.6%
Hydro One 2 BCP	$3.0	$3.0	167.9%	167.9%

Table 9 demonstrates that TMMC's revenue-to-cost ratio at the current OEB-approved rates is 212.2%. This clearly demonstrates that current Large Use class rates are significantly above the cost of providing service to TMMC and should be significantly reduced to more closely reflect the actual cost of providing distribution service to TMMC.

Q. WHY SHOULD THE BOARD ADOPT THE TWO LARGE USE CLASSES/DIRECT ASSIGNMENT CLASS COST-OF-SERVICE STUDY PRESENTED IN SCHEDULE JP-11?

A. The Two Large Use Classes/Direct Assignment CCOSS presented in **Schedule JP-11** is consistent with the principles of cost causation while the Settlement CCOSS is not. This is because the Two Large Use Classes/Direct Assignment CCOSS recognizes TMMC's unique circumstances as follows:

Q. ARE THE SAME TWO CHANGES ALSO REFLECTED IN UPDATED SCHEDULE JP-6 PROVIDED IN APPENDIX C?

A. Yes.

Q. WHAT ARE YOUR SPECIFIC CONCERNS ABOUT APPLYING THE BOARD'S GUIDANCE ON ADJUSTMENTS TO FIXED CHARGES IN THIS PROCEEDING?

A. I would observe that applying the OEB's guidance would result in a *maximum* monthly fixed charge for TMMC of approximately $244 per month based on the Two Large Use Classes/Direct Assignment study shown in **Schedule JP-11**.[16] By contrast, the maximum monthly fixed charge for the other Large Use customer would be $878 per month.[17] Not only is there a substantial difference in the cost-based monthly fixed charge between TMMC and the other Large Use customer, the current OEB-approved $8,976.07 Large Use Service charge is clearly excessive. Thus, my first concern is that retaining the current Service Charge would not be consistent with designing cost-based rates. My second concern is that there is a significant difference between the TMMC and other Large Use customer monthly fixed charge. This difference supports establishing a separate TMMC customer class.

Q. PLEASE DESCRIBE YOUR REVISED RATE DESIGN RECOMMENDATIONS.

A. **Schedule JP-13** shows the derivation of my recommended rate design for Supplementary Distribution service provided to TMMC. To be clear, the term "Supplementary" refers to the "regular" Distribution service provided to a customer for load that is not otherwise supplied from the customer's LDG facilities.

[16] **Schedule JP-11** Workpaper, Sheet O2: Monthly Fixed Charge Min & Max Worksheet.

[17] *Id.*

Q. PLEASE DISCUSS SCHEDULE JP-13.

A. **Schedule JP-13** is based on a target revenue requirement of $420,157. This amount was derived from **Schedule JP-11** and adjusted to result in a 1.15 revenue-to-cost ratio. A summary of my recommended TMMC rate design is provided in Table 10.

Table 10
Recommended TMMC Rate Design

Rate	Allocated Cost	Target Revenues	Rate	Units	Reference
	(1)	(2)	(3)	(4)	(5)
Revenue Requirement	$391,949	$420,157			Sch. 11, Row 40 Sch. 13, pg. 1, Line 5
Service Charge		$107,713	$8,976.07	Per Month	Sch. 13 pg. 1, Line 6
Distribution Volumetric Rate		$312,444	[redacted]	Per kW	Sch. 13, pg. 1, Line 10

The Distribution Volumetric Rate would recover $312,444 (based on using the currently OEB-approved Service Charge).

Q. HOW WAS THE DISTRIBUTION VOLUMETRIC RATE WITH STANDBY SERVICE DERIVED?

A. The proposed Distribution Volumetric Rate was designed to recover the cost of the M24 and M30 Feeders used exclusively by TMMC. The cost of these Feeders is fixed because they were installed prior to when TMMC energized its LDG facilities and, consequently, there is more than sufficient capacity to serve TMMC's total (Supplementary and Standby service) requirements even if one or both of its LDG units were out of service. In other words, there are no incremental costs to provide Standby service to TMMC. Accordingly, the Distribution Volumetric Rate should account for the amount of TMMC's Contract Standby Demand. As discussed later, I have assumed that TMMC would contract for 6,900 kW of Standby service.

- A Daily Volumetric Rate to recover the cost of shared distribution facilities.

The Contract Volumetric Rate would apply regardless of when or how often Standby Distribution service is provided. The Daily Volumetric Rate would apply when Standby Distribution service is actually used. Thus, customers using more Standby Distribution service would pay more than customers that use little or no Standby Distribution service. Further, to ensure that a LDG customer does not pay more for Standby Distribution service than for a comparable amount of Supplementary Distribution service, the sum of the Contract and Daily Volumetric Rate applied in any month would not exceed the otherwise applicable Distribution Volumetric Rate. In other words, a customer that uses Standby Distribution service for an entire month would pay the same total volumetric charges as would a similarly sized customer taking only Supplementary Distribution service.

Q. REFERRING TO SCHEDULE JP-14, HOW DID YOU DERIVE THE CONTRACT VOLUMETRIC RATE?

A. The recommended Contract Volumetric rate is $[redacted] per kW. This rate recovers the cost of the local distribution facilities directly assigned to TMMC and the corresponding overhead costs. The derivation of the rate is shown in **Schedule JP-13,** page 1 (line 9). It assumes that TMMC will establish a Standby Contract Demand of 6,900 kW. This would be in addition to TMMC's Supplementary service billing demand which is derived in **Schedule JP-13**, page 2.

Q. HOW DID TMMC DETERMINE THAT IT WOULD ESTABLISH A STANDBY CONTRACT DEMAND OF 6,900 KW?

A. I am advised by TMMC that the 6,900 kW Standby Contract Demand reflects a combination of factors:

- TMMC's outage history (*i.e.,* **Schedule JP-7**);
- The fact that outages are unlikely to coincide with the monthly peak demand; and
- The low probability of a simultaneous outage of both LDG units.

Q. HOW DID YOU DERIVE THE DAILY VOLUMETRIC RATE?

A. As previously explained, the Daily Volumetric Rate applicable to TMMC is designed to recover shared facilities costs, which in the case of TMMC are the costs of the primary poles allocated to TMMC. The allocated costs were derived from the Two Large Use Classes/Direct Assignment study. As shown on **Schedule JP-14** (line 2), the corresponding annual unit cost is $[redacted] per kW-month. The [redacted] monthly charge was then restated into a Daily Volumetric Rate by dividing $[redacted] by the number of weekdays in a typical billing month, or 20.9 (line 3). Thus, the Daily Volumetric rate applicable to TMMC would be $[redacted] per kW-Day line 4).

Q. WHEN WOULD THE DAILY VOLUMETRIC RATE APPLY?

A. The Daily Volumetric Rate would apply when the customer uses Standby Distribution service; that is, when the customer establishes a higher monthly peak demand while it is also experiencing a generator outage. The customer would have to notify Energy+ when an outage occurs and when the LDG has been fully restored. The daily demand would be the difference between the monthly peak demand established during an outage and the previously established monthly peak demand.

Further, the Daily Volumetric Rate would only apply during weekdays, excluding public holidays. This would provide a price signal to encourage a customer to schedule or defer outages to the off-peak hours.

Q. CAN THE GENERAL APPROACH DESCRIBED IN SCHEDULE JP-14 ALSO BE USED TO DESIGN STANDBY RATES FOR OTHER CUSTOMER CLASSES?

A. Yes. The Contract Volumetric Rate for each class would be designed to recover the costs of local distribution facilities used to serve that class. Because Energy+'s other end-use customer classes are served from an integrated (rather than radial) system, the local distribution facilities could include primary and secondary distribution, while the shared facilities would include >50 kV (and, possibly, certain primary distribution facilities). The derivation of the applicable rate for the GS 50 – 999 kW class is illustrated in **Schedule JP-15**.

Q. HOW DID YOU DERIVE THE CONTRACT VOLUMETRIC RATE FOR THE GS 50 – 999 KW CLASS?

A. Referring to **Schedule JP-15**, page 1, the Contract Volumetric Rate is based on the assumption that local distribution facilities include both Primary and Secondary demand-related costs (line 1) and on the test-year billing demand (line 2). Using the CCOSS in **Schedule JP-11**, the GS 50 – 999 kW class was allocated local distribution costs of $4.360 million (line 1). The derivation of the $4.360 million of allocated local distribution costs is shown in **Schedule JP-15**, page 2. The Contract Volumetric Rate of $2.779 per kW (page 1, line 3) was derived by dividing the allocated local distribution costs (line 1) by the test-year billing determinants (line 2).[21]

Q. HOW DID YOU DERIVE THE DAILY VOLUMETRIC RATE FOR THE GS 50 – 999 KW CLASS?

A. The Daily Volumetric rate is based on the cost of Energy+'s shared distribution facilities (**Schedule JP-15**, page 1, line 4). Based on the Settlement Proposal, the cost of these facilities is $1.382 million. The components of the $1.382 million are shown in **Schedule JP-15**, page 3.

Referring again to **Schedule JP-15**, page 1, I then divided this amount by the total 12CP demand of 2,528,721 (line 5) to derive a system unit cost of $0.547 per kW-month (line 6). The final step was to restate the system unit cost to an equivalent cost for secondary voltage by applying the applicable secondary voltage distribution loss factor (line 7). This resulted in a charge of $0.561 per kW-month (line 8). The $0.561 monthly charge can then be restated into a Daily Volumetric Rate by dividing the former by the number of weekdays in a typical billing month, or 20.9 (line 9). This will result in a Daily Volumetric rate of $0.027 per kW-Day (line 10).

Q. COULD THE SAME PROCESS BE USED TO ESTABLISH STANDBY RATES FOR ANY CUSTOMER CLASS?

A. Yes. The process illustrated in **Schedule JP-15** would apply equally to all (non-TMMC) customer classes. In fact, because the Daily Volumetric rate is based on

[21] In the work papers to **Schedule JP-11**, I have created a new worksheet (Local Shared Costs) that can be used to derive the Contract Volumetric Rate for the other general service classes using the same methodology as shown in **Schedule JP-15**.

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Sheet O1 Revenue to Cost Summary Worksheet - Two Large Use Classes/Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate

Line	Description	Total	1 Residential	2 GS <50	3 GS> 50- 999 kW	5 GS> 1,000 - 4,999 kW	6 Large Use 1	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor Hydro One - CND
1	Distribution Revenue at Existing Rates	$33,454,352	$17,528,595	$4,131,617	$7,466,138	$2,140,493	$259,214	$671,811	$14,573	$64,042	$50,527
2	Miscellaneous Revenue (mi)	$2,022,079	$1,357,570	$222,389	$245,250	$91,016	$9,890	$56,446	$1,326	$4,532	$634
		Miscellaneous Revenue Input equals Output									
3	**Total Revenue at Existing Rates**	$35,476,431	**$18,886,164**	**$4,354,006**	**$7,711,388**	**$2,231,509**	**$269,104**	**$728,257**	**$15,899**	**$68,574**	**$51,160**
4	Factor required to recover deficiency (1 + D)	1.0261									
5	Distribution Revenue at Status Quo Rates	$34,327,788	$17,986,236	$4,239,487	$7,661,066	$2,196,378	$265,982	$689,351	$14,953	$65,714	$51,846
6	Miscellaneous Revenue (mi)	$2,022,079	$1,357,570	$222,389	$245,250	$91,016	$9,890	$56,446	$1,326	$4,532	$634
7	**Total Revenue at Status Quo Rates**	$36,349,867	**$19,343,806**	**$4,461,876**	**$7,906,317**	**$2,287,394**	**$275,871**	**$745,797**	**$16,279**	**$70,246**	**$52,479**
	Expenses										
8	Distribution Costs (di)	$4,860,260	$2,894,330	$496,785	$924,005	$368,553	$37,318	$89,526	$4,097	$13,539	$0
9	Customer Related Costs (cu)	$4,893,912	$3,864,514	$637,554	$290,384	$88,328	$3,679	$1,531	$181	$1,388	$2,419
10	General and Administration (ad)	$8,577,377	$5,835,887	$983,938	$1,078,443	$404,663	$36,580	$82,040	$3,850	$13,384	$6,040
11	Depreciation and Amortization (dep)	$6,376,711	$3,704,003	$787,999	$1,234,577	$426,165	$44,450	$102,838	$5,032	$16,591	$2,921
12	PILs (INPUT)	$768,693	$437,563	$85,014	$155,976	$56,051	$5,672	$14,651	$679	$2,238	$675
13	Interest	$4,420,641	$2,516,359	$488,905	$896,993	$322,342	$32,617	$84,255	$3,904	$12,870	$3,882
14	**Total Expenses**	$29,897,594	**$19,252,655**	**$3,480,197**	**$4,580,378**	**$1,666,102**	**$160,315**	**$374,841**	**$17,742**	**$60,010**	**$15,936**
15	**Direct Allocation**	**$245,744**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$22,095**
16	Allocated Net Income (NI)	$6,206,530	$3,532,940	$686,418	$1,259,368	$452,565	$45,793	$118,293	$5,481	$18,069	$5,450
17	**Revenue Requirement (includes NI)**	$36,349,867	$22,785,595	$4,166,614	$5,839,746	$2,118,667	$206,108	$493,134	$23,223	$78,079	$43,481
	Rate Base Calculation										
	Net Assets										
18	Distribution Plant - Gross	$197,935,948	$113,846,650	$22,412,628	$39,822,618	$14,301,708	$1,473,960	$3,760,154	$172,867	$569,420	$21,826
19	General Plant - Gross	$15,515,903	$8,867,957	$1,720,649	$3,118,730	$1,112,648	$115,634	$297,680	$13,780	$45,279	$14,580
20	Accumulated Depreciation	($25,245,338)	($14,456,225)	($3,130,320)	($4,913,552)	($1,856,299)	($177,242)	($423,008)	($18,397)	($62,019)	($15,707)
21	Capital Contribution	($31,975,089)	($18,800,132)	($3,623,027)	($6,157,115)	($2,108,502)	($252,518)	($639,182)	($29,448)	($95,175)	($3,739)
22	**Total Net Plant**	$156,231,424	**$89,458,250**	**$17,379,930**	**$31,870,681**	**$11,449,556**	**$1,159,833**	**$2,995,644**	**$138,802**	**$457,505**	**$16,960**
23	**Directly Allocated Net Fixed Assets**	$898,672	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$121,453**
24	**Working Capital**	$16,695,208	**$5,237,222.63**	**$1,953,882**	**$4,710,066**	**$2,183,424**	**$293,927**	**$48,068**	**$1,783**	**$23,128**	**$117,405**
25	**Total Rate Base**	$173,825,304	**$94,695,473**	**$19,333,812**	**$36,580,746**	**$13,632,979**	**$1,453,761**	**$3,043,711**	**$140,584**	**$480,633**	**$255,819**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	**84.89%**	**107.09%**	**135.39%**	**107.96%**	**133.85%**	**151.24%**	**70.10%**	**89.97%**	120.69%

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Sheet O1 Revenue to Cost Summary Worksheet - Two Large Use Classes/Direct Assignment

Class Revenue, Cost Analysis, and Return on Rate

Line	Description	Total	12 Embedded Distributor Waterloo North Hydro - CND	13 Embedded Distributor Hydro One 1 - BCP	14 Embedded Distributor Brantford Power - BCP	15 Embedded Distributor Hydro One 2 - BCP	16 Large Use 2
1	Distribution Revenue at Existing Rates	$33,454,352	$221,287	$115,168	$5,388	$4,655	$780,844
2	Miscellaneous Revenue (mi)	$2,022,079	$1,666	$351	$201	$224	$30,585
		Mis					
3	**Total Revenue at Existing Rates**	$35,476,431	**$222,954**	**$115,519**	**$5,589**	**$4,879**	**$811,429**
4	Factor required to recover deficiency (1 + D)	1.0261					
5	Distribution Revenue at Status Quo Rates	$34,327,788	$227,064	$118,174	$5,529	$4,777	$801,231
6	Miscellaneous Revenue (mi)	$2,022,079	$1,666	$351	$201	$224	$30,585
7	**Total Revenue at Status Quo Rates**	$36,349,867	**$228,731**	**$118,525**	**$5,730**	**$5,000**	**$831,816**
	Expenses						
8	Distribution Costs (di)	$4,860,260	$0	$0	$0	$0	$32,108
9	Customer Related Costs (cu)	$4,893,912	$405	$405	$705	$1,620	$799
10	General and Administration (ad)	$8,577,377	$17,599	$3,502	$1,820	$1,358	$108,274
11	Depreciation and Amortization (dep)	$6,376,711	$4,561	$836	$602	$0	$46,137
12	PILs (INPUT)	$768,693	$2,682	$491	$199	$0	$6,803
13	Interest	$4,420,641	$15,424	$2,826	$1,142	$0	$39,120
14	**Total Expenses**	$29,897,594	**$40,672**	**$8,060**	**$4,468**	**$2,978**	**$233,241**
15	**Direct Allocation**	$245,744	**$95,569**	**$17,510**	**$6,787**	**$0**	**$103,784**
16	Allocated Net Income (NI)	$6,206,530	$21,656	$3,968	$1,604	$0	$54,925
17	**Revenue Requirement (includes NI)**	$36,349,867	$157,897	$29,537	$12,859	$2,978	$391,949
	Rate Base Calculation						
	Net Assets						
18	Distribution Plant - Gross	$197,935,948	$0	$0	$3,252	$0	$1,550,865
19	General Plant - Gross	$15,515,903	$57,785	$10,587	$4,285	$0	$136,306
20	Accumulated Depreciation	($25,245,338)	($33,215)	($6,085)	($3,555)	$0	($149,713)
21	Capital Contribution	($31,975,089)	$0	$0	($557)	$0	($265,694)
22	**Total Net Plant**	$156,231,424	**$24,571**	**$4,502**	**$3,426**	**$0**	**$1,271,765**
23	**Directly Allocated Net Fixed Assets**	$898,672	**$525,336**	**$96,250**	**$37,305**	**$0**	**$118,327**
24	**Working Capital**	$16,695,208	**$539,518**	**$113,175**	**$3,505**	**$399,953**	**$1,070,152**
25	**Total Rate Base**	$173,825,304	**$1,089,425**	**$213,927**	**$44,235**	**$399,953**	**$2,460,244**
26	**REVENUE TO EXPENSES STATUS QUO%**	100.00%	144.86%	401.27%	44.56%	167.90%	212.23%

ENERGY+, Inc.

TMMC Recommended Supplementary Distribution Service Rate Design

Line	Description	Cost	Billing Units		Rate	Reference
		(1)	(2)		(3)	(4)
1	**Total Revenue Requirement**	$391,949				Schedule JP-11, Row 40
2	Revenue-to-Cost Ratio	1.15				Assumption
3	Target Revenue	$450,741				Line 1 x Line 2
4	Less: Other Revenues	$30,585				Schedule JP-11, Row 2
5	Target Rate Design Revenue	$420,157				Line 3 - Line 4
6	Service Charge	$107,713	12	Bills	$8,976.07	
7	Revenues to be Recovered In Distribution Volumetric Rate	$312,444				Line 5 - Line 6
8	**Shared Facilities Cost**	$164,161	[redacted]	kW	[redacted]	Line 14
9	**Local Facilities Cost**	$148,283	[redacted]	kW	[redacted]	Line 15
10	**Distribution Volumetric Rate**	$277,648			[redacted]	Line 8 + Line 9
	Revenue Requirement By Function:					
11	Target Rate Design Revenue	$420,157				
12	Less Service Charge Revenue	$107,713				
13	Demand-Related Revenue Required	$312,444				
14	Shared Facilities (Primary Poles)	$164,161	JP-11, Sht O2.2			
15	Local Facilities	$148,283				

REDACTED VERSION

ENERGY+, Inc.

TMMC Class Billing Demand
(Amounts in kW)

Line	Description	Amount	Reference
		(1)	(2)
1	Energy+ Projection	300,496	Energy+ Response to TCQ TMMC IR-2(a)
2	Less: Energy+ LDG Adjustment	[redacted]	Schedule JP-1
3	Supplementary Billing Demand		Line 1 - Line 2
4	Standby Contract Demand	82,800	6,900 kW per Month
5	Total Primary Substation - Feeder Billing Demand	[redacted]	Line 3 + Line 4

ENERGY+, Inc.

TMMC Recommended Standby Distribution Service Rate Design

Line	Description	Rate	Reference
		(1)	(2)
1	**Contract Volumetric Rate (Local Facilities)**	[redacted]	Schedule JP-13, pg. 1, Line 9
	Daily Volumetric Rate:		
2	Shared Facilities Unit Cost	[redacted]	Schedule JP-13, pg. 1, Line 8
3	No. of Weekdays Per Billing Month	20.9	
4	**Daily Volumetric Rate**	[redacted]	Line 2 ÷ Line 3
5	**Monthly Maximum Standby Volumetric Rate**		Line 1 + Line 2

ENERGY+, Inc.
Recommended Standby Distribution Service Rate Design
Applicable to the GS 50 - 999 kW Customer Class

Line	Description	Rate	Reference
		(1)	(2)
	Contract Volumetric Rate:		
1	Local Distribution Costs	$4,359,649	Schedule JP-15, pg. 2
2	Billing Demand	1,568,556	Schedule JP-11, Sht. I6.1
3	**Contract Volumetric Rate**	$2.779	Line 1 ÷ Line 2
	Daily Volumetric Rate:		
4	Shared Distribution Costs	$1,382,087	Schedule JP-15, pg. 3
5	Sum of 12CP Demand at Source	2,528,721	Schedule JP-11, Sht. I8
6	Unit Cost	$0.547	Line 4 ÷ Line 5
7	Distribution Secondary Loss Factor	2.61%	Application Exhibit 8, Table 8-16
8	Unit Cost at Secondary Voltage	$0.561	Line 6 x (1 + Line 7)
9	No. of Weekdays Per Billing Month	20.9	
10	**Daily Volumetric Rate**	$0.027	Line 8 ÷ Line 9

ENERGY+, Inc.

Local Distribution Costs
GS 50 - 999 kW Customer Class

Line	Description	Amount
		(1)
1	Distribution Costs	$799,646
2	General & Administrative	$703,173
3	Depreciation & Amortization	$1,009,046
4	PILS	$135,822
5	Interest Expense	$781,090
6	Total Expenses	$3,428,777
7	Allocated Net Income	$1,096,642
8	Total Revenue Requirement	$4,525,419
8	Revenue-to-Cost Ratio	1.00
9	Miscellaneous Revenue	$165,770
10	Revenue Requirement	$4,359,649

ENERGY+, Inc.

Shared Distribution Costs Based on The Settlement Revenue Requirement

Line	Description	Amount
		(1)
1	Distribution Costs	$313,513
2	General & Administrative	$275,689
3	Depreciation & Amortization	$171,804
4	PILS	$46,278
5	Interest Expense	$266,139
6	Total Expenses	$1,073,424
7	Allocated Net Income	$373,656
8	Miscellaneous Revenue	$64,993
9	Revenue Requirement	$1,382,087

ENERGY+, Inc.
Revenues From TMMC Recommended
Standby Distributiion Service Rate

Line	Description	Rate	Billing Units		Revenues
		(1)	(2)		(3)
1	**Contract Volumetric Rate**	[redacted]	82,800	kW	[redacted]
2	**Daily Volumetric Rate**	$0.029	[redacted]	kW	
3	**Total Standby Service Revenues**				

Col. References:
(1) Schedule JP-14, page 1.
(2) Assumed Standby Contract Demand; Schedule JP-7 Revised.
(3) Col (1) x Col (2).