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SURREBUTTAL TESTIMONY
OF
HONG HU

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2002-424

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Hong Hu, Public Utility Economist, Office of the Public Counsel (Public Counsel), P. O. Box 7800, Jefferson City, Missouri 65102.

Q. HAVE YOU FILED ANY PREVIOUS TESTIMONY IN THIS CASE?

A. Yes, I filed direct testimony and rebuttal testimony on the issue of class cost of service (CCOS) and rate design.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to file Public Counsel's updated CCOS study and to respond to the rebuttal testimonies filed by Praxair regarding CCOS studies.

I. COST OF SERVICE STUDY

Q. WHAT IS THE MAIN CONTROVERSY AMONG ALL PARTIES' REBUTTAL TESTIMONIES REGARDING CCOS STUDIES?

A. The main controversy among all parties regarding cost of service studies is the appropriate method of allocating production and transmission plant costs. Public Counsel and the Staff criticize the "Average and Excess" ("A&E") methods used by the Company and Praxair because the A&E method produces results that are similar or identical to a peak responsibility method, and because the A&E method fails to account for demands in every hour that the production capacity is utilized to serve load (Watkins rebuttal, page 2; Hu rebuttal, pages 3 through 5). Praxair criticizes both the Public Counsel's 12-month NCP average and peak method and the Staff's time-of-use method.

Q. ON PAGE 3 OF HIS REBUTTAL TESTIMONY, PRAXAIR'S WITNESS MR. BRUBAKER STATED THAT HE WAS CRITICAL OF YOUR ALLOCATION OF GENERATION AND TRANSMISSION FIXED COSTS BECAUSE YOU HAVE NOT "ADDRESSE[D] THE BASIS FOR SELECTING THIS ALLOCATION METHOD" AND BECAUSE THIS METHOD DOES NOT "MIRROR HOW UTILITIES INCUR COSTS". CAN YOU DESCRIBE HOW ELECTRIC PRODUCTION COSTS ARE INCURRED?

A. Yes. In short, electric utilities choose a mix of different types of electric generation plants to minimize the total generation cost and to satisfy the entire system load. An electric utility's load varies during the day, generally with heavy demand from 10am to 10pm and with much less demand in the night. Load also varies during the year, with heavy demand during the heating and air conditioning seasons. An electric utility usually cannot store its production, and must have the

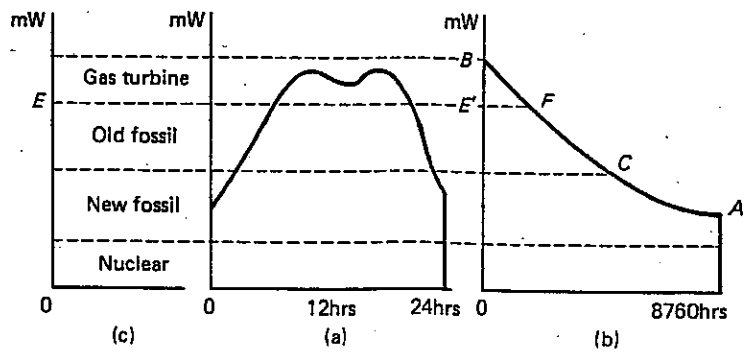
generators ready to meet those periods of maximum demand. The generation facilities must be in place even if they are expensive to maintain and stand idle for much of the time. The utility needs to serve the entire load, but it does not need the same kind of power plant to meet all of its capacity and energy requirements.

Theoretically, the utility would want to minimize the investment it has in plant that is likely to be idle most of the time, and would want the plant that will be in operation most of the time to be as reliable and economical as possible. The solution is to build what are called base load plants to meet the minimum around-the-clock load. Because fixed costs can be spread over many hours of operation, those plants tend to be large and expensive-to-build machines that burn low cost fuels. At the other extreme, the utility builds and runs peaking units for those brief periods of peak demand on the system. Those units are generally inexpensive to build because fixed costs have to be spread over a brief period of usage, but fuel costs often are high. The industry also has an intermediate category of generators that are used less than base load and more than peaking units.

Figuring out how much of each type of plant to build in order to minimize the utility's total production cost is a complicated and dynamic problem. System planning problems are solved typically by engineers using complicated computer programs, and there exists a considerable amount of literature on the subject. A simplified tool for understanding the system planning practice is load and load-duration curves. A load curve plots demands over a given time period. The load-duration curve measures how long a level of demand "lasts" over the year. Figure 1 shows an example of a load curve (a) and a load-duration curve (b). A load-duration curve is obtained by starting with the lowest level of demand in any hour of the year. Since all demands were above this level for the rest of the year, this

demand was maintained for the whole year resulting in point A in Figure 1(b). Similarly, if we rank demands in ascending order, we are able to plot the whole load-duration curve AB. Thus, at point C, this level of load is maintained for about half the year.

Figure 1. Example of load curve and load-duration curve

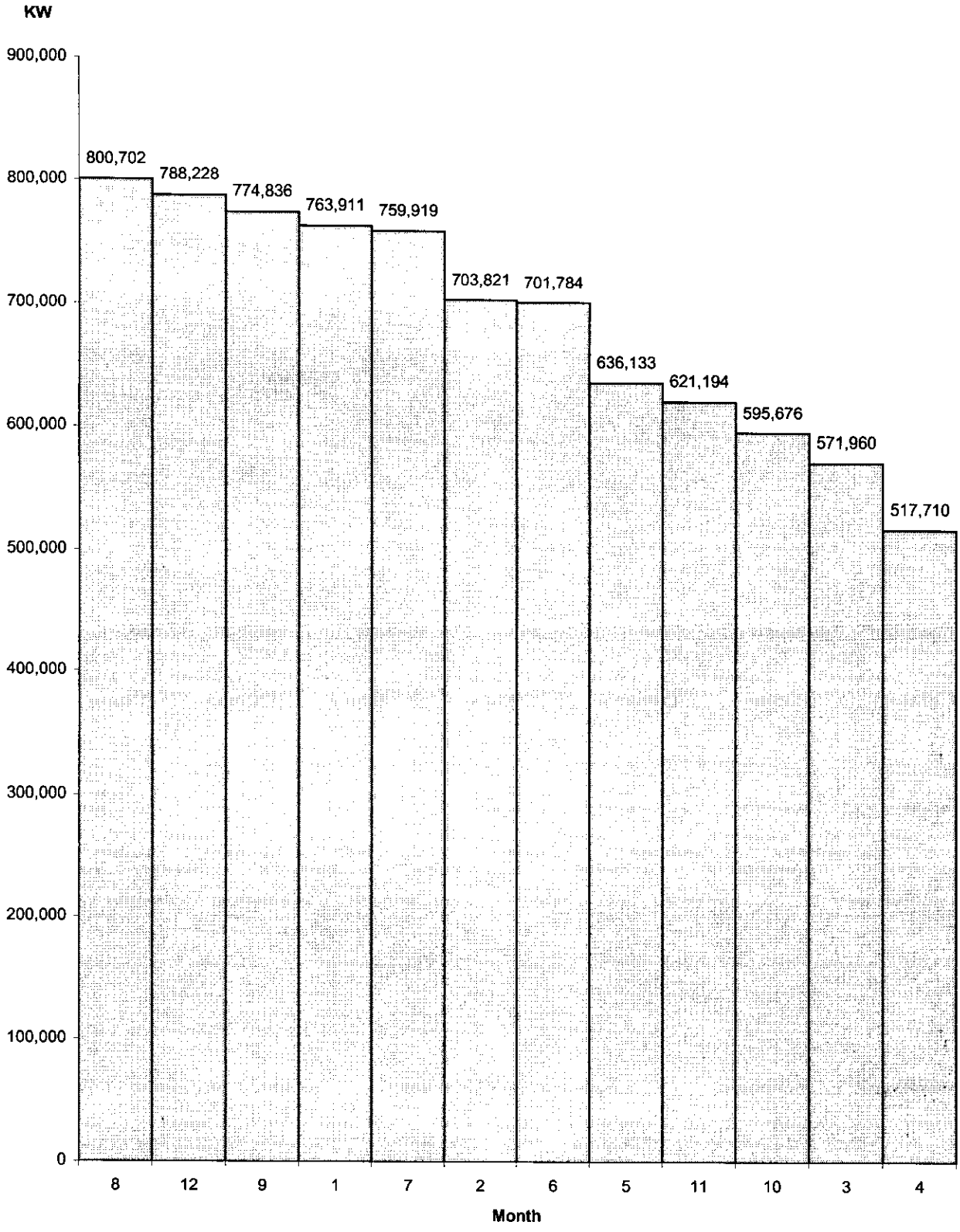


Looking at Figure 1(c), it is clear that the load-duration curve provides a basis for choosing a cost-minimizing plant mix for a given expected load profile. The shape of the load-duration curve is as important as, if not more important than, the magnitude of the peak demand in determining how production costs are to be incurred for an electric utility.

Q. PLEASE EXPLAIN HOW PUBLIC COUNSEL'S METHOD REFLECTS HOW UTILITIES INCUR COSTS.

A. Public Counsel believes that cost allocation should reflect cost causation. Figure 2 on the next page is an approximate load-duration curve for Empire. It is an approximation because it is derived by ranking monthly demands instead of hourly demands. From the curve, we can see that a 517,710 kW load has been served around the year. Therefore, the cost of production plants that serve this particular load should be spread over all hours. Similarly, the portion of

Figure 2. Empire's Load-Duration Curve



production plants that are used to satisfy the additional demand above the base load, should be spread over all hours that these plants are running. For example, loads over 788,228 kW only occurred in two months (July and August), and thus the cost of the peak load facilities that are installed to serve this peak load should be spread only to the hours in these two months. The Public Counsel's method shown in Schedule HH DIR-1 of my direct testimony accomplishes exactly such a task. The peak demands are ranked first to determine their order in the load-duration curve and then the costs are spread to each month accordingly. After the costs are spread to each month, the monthly production costs are allocated to each customer class based on their load during that month.

A method that utilizes hourly demand instead of monthly demand could obtain a more accurate result but I believe the Public Counsel's method produces a reasonably close result. A method that only utilizes the peak demand in production plant cost allocation is much worse at mirroring how utilities incur costs than Public Counsel's method.

Q. ON PAGE 4 OF HIS REBUTTAL TESTIMONY, MR. BRUBAKER WAS ALSO CRITICAL OF YOUR METHOD BECAUSE HE BELIEVED THAT YOU SHOULD USE CLASS SHARE OF COINCIDENT PEAK DEMANDS INSTEAD OF NON-COINCIDENT PEAK DEMANDS IN DEVELOPING THE ALLOCATOR. HAVE YOU EXAMINED THE DIFFERENCE?

A. Yes. I have developed the allocator using class share of coincident peak demands and the difference between the two results is minimal. I have chosen to use non-coincident peak demands because it is likely to be a better representation of the class share of total hours that any production facility is utilized in a certain month.

Q. ON PAGE 5 OF HIS REBUTTAL TESTIMONY, MR. BRUBAKER INDICATED THAT YOUR METHOD HAS "NO CLAIM TO ACCURACY OR THE REPRESENTATION OF COST CAUSATION" BECAUSE IT "GIVE[S] SIGNIFICANT WEIGHT TO LOADS OCCURING IN OFF-PEAK HOURS AND IN OFF-PEAK MONTHS". DO YOU AGREE?

A. No. The goal here is to allocate the total cost of the entire production system, not only the cost of some peak units that are needed in the peak months. As shown in Figure 2 above, five months (January, July, August, September, December) had similar load levels at or above 760,000 kW, i.e. 95% of the maximum system loads. August is the peak month, but should the other four "off-peak" months receive weights similar to the weight that August receives? Of course they should. Furthermore, five more months (February, May, June, October, November) had loads near or above 600,000 kW, i.e. 75% of the maximum system load. Should these "off-peak" months receive some weight, albeit smaller than the weight that August receives? Again, of course the answer is yes. In fact it is only reasonable that all hours that the production facility is running receive some weight, with peak hours and peak months receiving more weights than non-peak months. That is exactly what Public Counsel's method does.

Mr. Brubaker would assign 100% weight to August, and zero weight to July, September, December, January and the rest of the months. I do not believe a method that gives the entire weight to one single peak month can be representative of cost causation, and that is what the "A&E" method does (or its equivalent "single peak responsibility" method) as advocated by Mr. Brubaker.

Q. MR. BRUBAKER INDICATED ON PAGE 5 THAT THAT THE "AVERAGE AND PEAK" METHOD IS NOT CORRECT BECAUSE IT USES THE TOTAL PEAK DEMAND RATHER THAN THE DIFFERENCE BETWEEN AVERAGE DEMAND AND CUSTOMER CLASS PEAK DEMAND, AND THUS IT DOUBLE COUNTS AVERAGE DEMAND. DO YOU AGREE WITH HIM?

A. No. The "Average and Peak" method is well documented in the NARUC electric cost of service manual. This method is effectively a weighted average of the two numbers: class peak demand and class average demand. You do not subtract one number from the other number when you try to obtain a weighted average of two numbers. This does not mean you have double counted one number or another. In fact, the resultant allocation factor for any customer class will fall between the range defined by corresponding allocation factors from an allocation based on average demand and an allocation based on a single peak demand. In contrast, despite the assertions made by advocates of A&E method that it is a method considering both peak and average demands, allocation factors derived from the A&E method often fall outside of the range defined by the corresponding allocation factors from the peak demand method and the average demand method.

Q. IN HIS CRITICISM OF THE STAFF'S TIME-OF-USE METHOD ON PAGE 7 OF HIS REBUTTAL TESTIMONY, MR. BRUBAKER IMPLIED THAT THE OFF-PEAK HOURS SHOULD NOT RECEIVE ANY ALLOCATION OF PRODUCTION AND TRANSMISSION COST BECAUSE "THEY WOULD NOT CAUSE THE NEED FOR THE ADDITION OF GENERATION OR TRANSMISSION CAPACITY". DO YOU AGREE?

A. No. The fixed cost of the production and transmission facilities should be spread across all hours that such facilities are running. It is because the production and transmission facilities can be used to serve all customers in all hours around a year

and that the large fixed cost can be shared by all customers' usage in all times that makes it economical to build a capital intensive electric generation and distribution system. If the cost were incurred to only serve loads in one single hour, even if it is the peak hour, it would still be cost prohibitive to have the generation and distribution system in place.

According to Mr. Brubaker's rational, if one only uses electricity in off-peak hours, he should be allowed to use the production and transmission facilities for free. Conversely, Mr. Brubaker appears to believe that if one happens to use electricity in the peak hour, then he should be responsible for the entire production and transmission plant cost. It should be remembered that there are 7,680 hours per year. It is not reasonable to force customers who use electricity in one particular hour to pay for the entire common cost of production and transmission facilities and let other customers who use electricity in the other 7,679 hours have a free ride. This is against the basic principle of joint production cost sharing of a multi-product or multi-service industry. All customers should be responsible for some portions of the cost of a facility as long as they are utilizing the facility. Both of the Public Counsel and Staff methods allocate costs to all users of a facility based on the relative use that each customer class has in each usage time period.

II. UPDATES OF PUBLIC COUNSEL'S CCOS STUDY

Q. WHY ARE YOU FILING AN UPDATED CCOS SUTY?

A. On page 6 of his rebuttal testimony, Mr. Brubaker pointed out that in Public Counsel's study revenues used for Praxair were the revenues reduced by the interruptible credit. I agree with Mr. Brubaker that Praxair's total revenue before

subtracting the interruptible credit should have been used instead and thus I have corrected this treatment accordingly. I have also corrected a few numbers where I unintentionally used data from a prior study.

Q. IS THERE ANY CHANGE IN THE RESULT OF YOUR UPDATED CCOS STUDY?

A. The result of my updated CCOS study is shown in Schedule HH SUR-2. The results for classes other than Praxair are not significantly changed from the previous result. However, the amount that Praxair is under-paying is reduced significantly. It is now shown to be under-paying by only 3.78% instead of 19.75%.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

OPC CCOS Study Summary

		TOTAL	Residential	SGS (Commercial, Small Heating, FM)	LGS (Gen Power & TEB)	Special Contract (Praxair)	Large Power	Other (El Furnace, Misc, & Ltg
1	O & M EXPENSES	141,913,308	64,561,742	17,885,284	35,441,297	1,731,619	19,845,226	2,448,140
2	DEPREC. & AMORT. EXPENSE	21,631,249	9,592,006	4,431,448	4,633,095	137,007	1,960,674	877,018
3	TAXES	19,144,425	9,079,572	2,520,940	4,612,077	182,120	2,249,990	499,726
4								
5	TOTAL EXPENSES AND TAXES	182,688,982	83,233,321	24,837,673	44,686,469	2,050,745	24,055,890	3,824,884
6								
7	CURRENT RATE REVENUE	221,570,437	101,523,163	32,689,777	54,795,175	2,265,092	26,067,115	4,230,115
8	OFFSETTING REVENUES:	1,571,753	731,005	203,230	384,211	16,813	200,852	35,643
9	Reveue Credits	(342,912)	(159,485)	(44,339)	(83,824)	(3,668)	(43,820)	(7,776)
10								
11	TOTAL CURRENT REVENUE	222,799,278	102,094,683	32,848,668	55,095,562	2,278,237	26,224,147	4,257,982
12	CLASS % OF CURRENT REVENUE	100.00%	45.82%	14.74%	24.73%	1.02%	11.77%	1.91%
13								
14	OPERATING INCOME	40,110,296	18,861,362	8,010,996	10,409,093	227,491	2,168,257	433,097
15								
16	TOTAL RATE BASE	579,320,075	278,959,521	77,204,076	137,735,975	4,880,047	63,310,652	17,229,804
17								
18	IMPLICIT RATE OF RETURN	6.92%	6.76%	10.38%	7.56%	4.66%	3.42%	2.51%
19								
20	OPC RECOMMENDED RATE OF RETURN	8.88%	8.88%	8.88%	8.88%	8.88%	8.88%	8.88%
21								
22	REQUIRED OPERATING INCOME							
23	Equalized (OPC) Rates of Return	51,443,623	24,771,605	6,855,722	12,230,955	433,348	5,621,986	1,530,007
24								
25	TOTAL COST OF SERVICE	234,132,605	108,004,926	31,693,394	56,917,424	2,484,093	29,677,876	5,354,891
26	CLASS % of COS	100.00%	46.13%	13.54%	24.31%	1.06%	12.68%	2.29%
27								
28	Allocation of difference between							
29	current revenue and recommended revenue	11,333,327	5,228,042	1,534,137	2,755,121	120,244	1,436,575	259,207
30	MARGIN REVENUE REQUIRED							
31	to Equalize Class ROR - Revenue Neutral	222,799,278	102,776,884	30,159,257	54,162,302	2,363,849	28,241,301	5,095,684
32								
33	COS LESS OFFSETTING REVENUES	221,570,437	102,205,364	30,000,366	53,861,915	2,350,705	28,084,269	5,067,818
34								
35	COS INDICATED REVENUE NEUTRAL SHIFT	0	682,201	(2,689,411)	(933,260)	85,613	2,017,154	837,703
36	% REVENUE NEUTRAL RATE INCREASE	0.00%	0.67%	-8.23%	-1.70%	3.78%	7.74%	19.80%
37	CLASS % OF REVENUE AFTER REVENUE SHIFT	100.00%	46.13%	13.54%	24.31%	1.06%	12.68%	2.29%

OPC Rate Design Summary

######		TOTAL	Residential	SGS (Commercial,Small Heating & FM)	LGS (Gen Power & TEB)	Special Contract (Praxair)	Large Power	Other (EF, Misc, & Ltg)
1	COS INDICATED RATE REVENUE INCREASE	0	682,201	(2,689,411)	(933,260)	85,613	2,017,154	837,703
2	COS REQUIRED % RATE REVENUE INCREASE	0.00%	0.67%	-8.23%	-1.70%	3.78%	7.74%	19.80%
3	CLASS % OF REVENUE AFTER REVENUE SHIFT	100.00%	46.13%	13.54%	24.31%	1.06%	12.68%	2.29%
4								
5	OPC RECOMMENDED REVENUE NEUTRAL SHIFT	0	341,101	(1,344,706)	(466,630)	42,806	1,008,577	418,851
6	OPC RECOMMENDED % RATE REVENUE INCREASE	0.00%	0.34%	-4.11%	-0.85%	1.89%	3.87%	9.90%
7	CLASS % OF REVENUE RECOMMENDED BY OPC	100.00%	45.97%	14.15%	24.52%	1.04%	12.22%	2.10%
8								
9	SPREAD OF REVENUE INCREASE							
10	$10 mil	10,000,000	4,597,376	1,414,678	2,451,976	104,161	1,221,990	209,819
11	$4.5 mil	4,500,000	2,068,819	636,605	1,103,389	46,872	549,896	94,419
12	$1 mil	1,000,000	459,738	141,468	245,198	10,416	122,199	20,982
13								
14	COMBINED IMPACT OF REVENUE INCREASE AND OPC REVENUE NEUTRAL SHIFT							
15	$10 mil	10,000,000	4,938,477	69,972	1,985,346	146,967	2,230,567	628,670
16	$4.5 mil	4,500,000	2,409,920	(708,101)	636,760	89,679	1,558,473	513,270
17	$1 mil	1,000,000	800,838	(1,203,238)	(221,432)	53,222	1,130,776	439,833
18								
19	COMBINED IMPACT ADJUSTED SO THAT NO CLASS RECEIVES NET DECREASE							
20	$10 mil	10,000,000	4,938,477	69,972	1,985,346	146,967	2,230,567	628,670
21	$4.5 mil	4,500,000	2,082,264	0	550,185	77,486	1,346,581	443,485
22	$1 mil	1,000,000	330,287	0	0	21,950	466,363	181,399
23								
24	% Increase							
25	$10 mil	4.51%	4.86%	0.21%	3.62%	6.49%	8.56%	14.86%
26	$4.5 mil	2.03%	2.05%	0.00%	1.00%	3.42%	5.17%	10.48%
27	$1 mil	0.45%	0.33%	0.00%	0.00%	0.97%	1.79%	4.29%