STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-12-06 APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE

June 30, 2009

By the following Commissioners:

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DECISION

appears that a simpler analysis, such as what was performed by the Department above yields similar results.

The Department determines, however, that the out-of-model, energy efficiency adjustment of (160,699 Mcf) is not appropriate, as the conservation adjustment mechanism (CAM) is the appropriate vehicle for lost margin recovery. If projected sales reductions are assumed when setting rates, the Department does not consider the margin from those savings as "lost." Nonetheless, the Department will not modify the Company's proposed sales forecast to reverse this out-of-model adjustment. Rather, in the applicable CAM reconciliation, the Company will recover or refund any variance in actual lost margins to the extent it differs from the allowed level of 160,699 Mcf during the rate year.

I. DECOUPLING / SSC TRUE-UP

1. Introduction

Decoupling refers to severing (decoupling) the link between a company's recovery of the distribution revenues approved by the Department in a rate application and the unpredictable volume of gas sales actually experienced following the implementation of new rates. If actual sales volumes exceed forecasted sales used to design rates, then actual revenues will exceed Department approved revenues, to the financial benefit of the company. Conversely, a shortfall in sales equates to a shortfall in revenues received by the company. Fundamentally, this misalignment of actually billed versus Department allowed revenues exists for all utilities that recover short-term fixed costs through a volumetric rate design. Volumetric rates continue to be used extensively to design Connecticut utility rates. The legislature addressed this issue in § 107 of PA 07-242, An Act Concerning Electricity and Energy Efficiency (Act) by requiring the Department to decouple gas and electric distribution revenues from sales volumes through one or more of the following strategies.

1. A mechanism that adjusts actual distribution revenues to allowed revenues.
2. Rate design changes that increase fixed distribution charges.
3. A sales adjustment clause, rate design changes that increase the amount of revenue recovered through fixed distribution charges, or both.

The Department is also required to consider the impact of decoupling on a company's return on equity and make necessary adjustments thereto.

2. Company Proposal

In the instant case, the Company proposed three decoupling strategies that collectively would fully decouple the Company's sales volume from its revenues.

1. A revenue true-up mechanism.
2. Increases in fixed customer charges.
3. Continuation of recently approved declining block volumetric rate structures.

Therrien, Simpson PFT, p. 5.

The revenue true-up mechanism is discussed here. Customer charges and rate structures are addressed in Section II.K. Rate Design.

The Company considers its decoupling proposal as "quid pro quo" ratemaking treatment that would allow it to enhance its commitment to conservation programs without hurting itself financially. Therrien and Simpson PFT, p. 10. The Company would increase expenditures for the programs referenced in the Joint 2009 Natural Gas Conservation Program and monitor emerging high efficiency gas equipment for inclusion in such programs. Response to Interrogatory GA-365. Decoupling would also result in less frequent rate increase proceedings, saving time and expense for all parties. Therrien and Simpson PFT, p. 12. According to the Company, current rate-making procedures no longer work because UPC, has declined precipitously during recent history. Therrien and Simpson PFT, p. 21. Consequently, revenues obtained from new and existing customers during periods of declining UPC would not be sufficient to cover normal activities and afford the Company a reasonable opportunity to earn a fair rate of return.

The Company believes that its decoupling proposal would mimic current rate-setting procedures under a more stable UPC environment. Therrien and Simpson PFT, p. 14. A 10% plus or minus change in heating degree days (HDD) would affect sales by approximately 1,818,000 Mcf, or $4 million at proposed rates. Late Filed Exhibit No. 91. Finally, the Company does not believe that any form of decoupling reduces business or financial risk for which equity investors require compensation. Consequently, no adjustment to ROE is required. The Company believes that decoupling is nothing more than a billing procedure. Makholm PFT, pp. 52 and 53; Response to Interrogatory GA-153.

The Company proposed modifying the existing conservation adjustment clause[10] (CAM) to accommodate its usage-oriented decoupling true-up mechanism. Essentially, post-rate case actual monthly UPC would be trued-up to the monthly normalized UPC approved in the latest rate application. Each month's true-up UPC would be multiplied by (1) the actual number of customers that month and (2) the volumetric rate[11] for the rate class in question. Interest, calculated at the Company's overall cost of money, would be added and the total true-up revenue (debit or credit) would be booked. Annually, the accumulated net true-up for each rate class would be included in next year's CAM. The annual CAM would also include a deferral factor to recover prior year collection differences.[12] This new, expanded CAM (ECAM) would apply to all firm rate classes except Rate LGS, which the Company argues reflects too divergent a range of customer sizes to generate a meaningful class-average UPC. Rate LGS customers would continue under the existing CAM. Therrien and Heintz PFT, pp. 25 and 26.

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[10] The current CAM recovers Department approved Company conservation expenditures from customers by means of a standalone, company-wide volumetric charge added to customer bills. It also employs an annual deferral mechanism to true-up collections.

[11] June through September sales will be multiplied by the first block distribution rate. The second block rate will be used during the remaining months.

[12] Being a volumetric rate, the CAM will over or under collect its target amount whenever actual sales deviate from assumed sales used to derive the annual CAM charge.

The Company further explained that the proposed ECAM could result in a monthly credit adjustment to one rate class while another class experiences a debit adjustment. The proposed ECAM adjusts for all changes in sales while the added revenue from new customers is retained by the Company. Response to Interrogatory GA-141. CNG argues that new-customer revenues must accrue to the Company as compensation for the costs of adding customers and to avoid creating a financial disincentive to adding customers. Response to Interrogatory GA-142.

3. Parties Positions

OCC's position is that the Department should not approve decoupling. But if a decoupling mechanism is approved, it should be an administratively simpler revenue decoupling model. Decoupling reduces the net economic welfare of customers by shifting business risks from the utility and capital market to customers. Briden PFT, pp. 8 and 20. In turn, the reduced business risk should be rewarded by the capital markets in the form of a lower cost of capital, which translates into a lower revenue requirement. Further, OCC does not believe that customer revenue savings flowing from a lower ROE can adequately compensate customers for their assumption of risk under decoupling. The risk shifting effects of decoupling through rate design or a true-up mechanism are identical. Briden PFT, pp. 13-15. OCC also claims that significant increases in rate design fixed cost recovery have already been made and that decoupling is not an effective means to promote conservation. Brief, p. 47.

AG believes that the Company's proposed decoupling plan should be rejected in its entirety. The plan unfairly and improperly shifts the business risk of sales from the Company to customers. The risk should lie with the Company, who's ROE provides a cushion against fluctuations in sales. Brief, p. 17. AG argues that decoupling actually creates a disincentive for customers to pursue conservation and load management programs by denying the full bill reduction benefits of their conservational efforts. If the Department does approve decoupling, AG believes it should be a simple revenue tracker with a substantial reduction in ROE of at least 100 basis points. Brief, pp. 19 and 20.

Environmental Northeast (ENE) supports full decoupling and believes the Company should receive the full benefit of adding new customers. But unlike the Company's proposal, ENE prefers a revenue per customer (RPC) decoupling mechanism for all firm rate classes. According to ENE, a RPC approach would eliminate the need to choose a distribution block rate to calculate the revenue effect of a change in UPC. Also, basing the revenue-oriented decoupling true-up on a per customer basis would automatically credit the Company with new customer revenues. ENE believes that Rate LGS should be included in the Company's RPC as well. Leaving Rate LGS outside the true-up is not consistent with the language or intent of the Act. Brief, pp. 1-4.

4. Discussion

The Department agrees with OCC and AG. Full decoupling compensates the Company for any type of reduction in consumption, such as warmer weather, customer loss, a deteriorating economy as well as permanent and price-induced conservation.

Clearly, the very large potential risk of revenue instability is shifted from the Company to customers. If the Company were to purchase an insurance instrument to guaranteed distribution revenues, the insurer would expect compensation and the Company would expect to make payment for the transfer of risk. The Company's decoupling proposal thrusts customers into the role of insurer without proffering compensation. By reviewing the level of compensation customers would require to breakeven under decoupling, the Department concluded that the requisite reduction in ROE needed as compensation would prove too draconian and actually impede the Company's ability to attract capital. The Company's own calculation shows that a 10% change in weather (HDDs) alone translates into a $4 million change in revenue. Add to this a continuing loss in UPC as predicted by the Company plus the uncertainty of a faltering economy and customers, conservatively, are at risk for $5 to $7 million of annual revenue shortfall. It will require a 100 basis point reduction in ROE (approximately a $3.8 million reduction in revenue) to provide customers with weather-only compensation, without anything additional. While decoupling can be expected, *a priori,* to reduce the frequency of rate applications and associated expense, the Company has not proffered any stay-out proposal. The enlarged conservation expenditures that the Company points to as the decoupling quid pro quo, will be paid for by ratepayers, who will also experience upward pressure on rates as UPC declines further. The Company's decoupling proposal guarantees a revenue stream free of customer compensation while holding open the freedom to file a rate application at will. The Company's decoupling proposal is denied.

The Department has and will continue to satisfy the Act by means of rate design. Since the adoption of the COSS standard in 2000, the Department has aggressively supported increases in fixed distribution rate designs, including the adoption of 100% cost-based customer and demand charges. In the instant case, customer and demand charges are being increased by the Department even as the overall level of proposed revenue is reduced. Earlier approved declining block rate structures are continued and volumetrically proposed SSC and TSC charges are being converted to demand charges. Also, the Company's existing CAM, which compensates the Company for measurable sales reductions from customer funded conservation programs, will continue going forward.

The Department believes that the existing, time-tested rate-setting principles afford Connecticut gas utilities ample opportunity to provide safe and efficient service while offering a reasonable opportunity to earn a fair rate of return on investment. The Department notes that the Company has filed only three rate applications since 1995, including the instant case. Further, the Company was ordered to file the instant case by the Department in response to an overearnings situation. The existing process has worked well for the Company.

5. SSC True-up

The Company proposed the establishment of a supplemental supply cost reconciliation mechanism (SSCRM). The Company defined SSCRM as consisting of three main items affected by the cost of gas: (1) commodity-related uncollectible expense; (2) gas inventory carrying charges; and (3) gas working capital. The proposed reconciliation mechanism or true-up would update the fixed revenue requirement established for each item in the instant rate case to reflect future actual expenses through a symmetrical balance sheet deferral procedure. Essentially, the debit or credit true-up would be booked monthly and deferred as a regulatory asset until the next rate application. The ending balance would then be subject to recovery or return treatment. The detailed mechanics of the true-up procedure were initially agreed to by Connecticut's three gas utilities in the Cost Allocation Decision. Marks, Rudiak, Therrien PFT, pp. 36-39.

The Company maintains that the volatility in the cost of natural gas, which drives these costs, is beyond its control. Aside from being a business risk for the Company, the volatility of these costs is also a risk to customers. In the absence of this true-up, customers may pay more if gas costs significantly drop below the level built into rates during the Company's last rate application. Had this true-up been in place earlier, it may have reduced earnings to the point of precluding recent overearnings, according to the Company. The Company's proposed true-up would stabilize earnings levels and strengthen its potential for obtaining an "A" credit rating. Marks, Rudiak, Therrien PFT, pp. 38 and 39. The Company also considers the true-up to be a mere billing mechanism that would not materially affect business risk from an investor's perspective. Response to Interrogatory GA-124.

OCC characterized the Company's SSCRM as a modification to the existing purchased gas adjustment clause. The Department previously denied similar SSCRM proposals in the Cost Allocation Decision and earlier in the SM Decision in Docket No. 04-05-11. OCC recommended that the Company's true-up proposal should be denied and an earning sharing mechanism (ESM) adopted instead. Brief, pp. 159 and 160.

AG believes that the Department should reject the Company's SSCRM because it unfairly and unnecessarily increases customer risk. Nonetheless, if the Department approves the mechanism, then AG argues for a significant downward adjustment to the Company's ROE to reflect the reduction in Company risk. Brief, p. 10.

While the Department understands the potential for excess supplemental gas cost payments by customers during a period of falling gas prices, it is also cognizant that the risk of price volatility is passed on to customers through the proposed true-up mechanism. As the Company stated, the true-up, which shifts risk to customers, enhances earnings stability leading to improved credit ratings. The improved financial position, in turn, translates into a lower ROE requirement by investors. Yet, the Company proffered no customer compensation. If the Company wanted to guarantee a fixed level of supplemental gas cost recovery through an insurance instrument, the insurance agent would demand compensation for the assumption of volatility risk, and the Company would expect to pay for the assignment of risk. Similarly, customers are entitled to compensation for the assumption of gas cost volatility.

As OCC mentioned, a true-up mechanism for these three issues has been examined and ruled against in previous Decisions. The Department sees nothing new like proffered customer compensation that warrants a change in its earlier position. Therefore, the Company's proposed SSCRM true-up is denied.

for Rate RSG to 17% for Rate LGS, with half of the rate classes within 1% of the system average ROR. The proposed RORs for each firm rate class range from approximately 3.36% for Rate RSG to 25% for Rate LGS, and only one rate class is within 1% of the system average ROR.

As the final revenue figure will need to be reallocated to each rate class, the Department does not have the appropriate COSS information to approve actual rate class revenue; but can approve or provide guidance with respect to the rate class ROR. The Department approves the proposed ROR of 3.36% for Rate RSG. Although the instant Decision results in an overall rate decrease, revenue responsibility for this rate class should not be reduced as it has been subsidized heavily historically. The proposed class ROR for Rate RSH will be lowered to equal the system average ROR approved herein. For the remaining rate classes, the proposed system average should be reasonably similar to the approved class ROR's relationship to the system average ROR from Docket No. 06-03-04PH02, to the extent that this does not result in rate shock for any of these particular classes. The Department is concerned about the recent rate impact of Rate SGS resulting from the migration of large customers from this class. Therefore, the change in total revenue allocation to this class should be modest. As the Company will be decreasing its revenue requirements, most customers should realize bill decreases, albeit to different extents. The Company will be directed to resubmit its class revenue allocations for Department approval as part of its Rate Design Plan.

3. Supply Charge

The Company set supply rates at full COSS levels for all firm sales classes. Supply rates are for illustrative purposes only, as gas costs are now recovered solely through the PGA. Therrien and Heintz PFT, p. 22.

The Department agrees with setting full COSS supply rates for each rate class, since this allocation methodology is consistent with prescribed PGA procedures. Bill comparisons at proposed and final rates in the instant case will best replicate actual bills calculated using PGA supply rates.

4. SSC/TSC

The Company proposed a volumetric SSC and TSC for all firm customer classes. Revenue Proof Exhibit V. As a general principle, the Company states that it would not be opposed to establishing SSC and TSC demand charges for rate classes with a transportation option (Rates RMDS, SGS, GS and LGS) because they already have a distribution demand charge. Nonetheless, the Company is not advocating for demand charges at this time. CNG is concerned about the effect of bill impacts on smaller customers and potential customer shift from sales to transportation service as a result of differences in SSC and TSC demand charges. Response to Interrogatory GA-302. The Company did agree to implement SSCs and TSCs that were either 100% demand or commodity. Tr. 3/25/09, p. 1643.

The Department believes that equal SSC and TSC demand charges should be implemented for each of the three C&I rate classes. The analysis done in GA-302, which gave the Company concern over bill impacts and potential customer shift, is not representative of the situation that exists under final rates in the instant case. First, GA-302 assumes Company proposed costs and ROR. Second, it reflects the proposed full cost assignment of SSC and TSC costs among rate classes. In contrast, the final Decision reflects a noticeably different set of costs, ROR and SSC-TSC COSS assignment among rate classes. The Company is directed to allocate SSC and TSC costs among C&I rate classes using the appropriate demand and commodity allocators to arrive at the correct revenue requirement for each rate class. All assets within a class will provide the same ROR as the rate class in question. The total class revenue requirement for both SSC and TSC will then be divided by the combined sales and FT peak demand to arrive at an equal SSC and TSC demand rate for each rate class. Rate RMDS will employ separate volumetric SSC and TSC rates, while Rates RSG and RSH will employ volumetric SSC rates only. The Department believes that the introduction of demand SSC and TSC rates satisfies the requirements of PA 07-242 § 107 stabilizing gross margin recovery for the Company.

5. Residential Service Rates

CNG proposed to move toward more cost-based rates by increasing customer charges for all of its firm rate classes and adjust the demand charge for Rate RMDS. Therrien and Heintz PFT, p. 16. The proposed 100% COSS based customer and demand unit rates[13] are as follows:

Rate	Customer	Demand
RSG	$42.81	-
RSH	$46.61	-
RMDS	$127.60	$1.1388

Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit VI.

Current customer charges for the residential rate classes collect less than half of actual customer costs. Customer costs not collected in a customer charge but rather a volumetric distribution charge send improper price signals and erode base delivery revenue as a result of declining NUPC and changes in weather. Therrien and Hientz PFT, p. 19.

a. Residential General

Based on the proposed revenue of $9,749,820, CNG proposed the following charges for Rate RSG: (a) a monthly Customer Charge of $18.50, an increase of $2.00 over the current charge of $16.50; (b) a single block Delivery Charge of $1.1500 per ccf, a slight increase over the current charge of $1.1434 per ccf; (c) a Supply Charge of

[13] The Department notes that there were discrepancies found in the pure COSS unit rates presented in Revenue Proof Exhibit IV and Revenue Proof Exhibit VI provided in the Response to Interrogatory GA-2, Supplement, Attachment 1. The Department finds Revenue Proof Exhibit VI contains the correct unit rates for all rate classes, and will use these rates in its analysis.

$0.7595 per ccf; and (d) a SSC of $0.0182 per ccf. Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit V.

In the Rate Design Decision, the Department approved a class ROR of approximately 3.0% for this class. As stated above, the Department approves maintaining the Company's proposed class average ROR of 3.36% for Rate RSG. This slight increase in class ROR moves the rate class closer to the system average ROR while limiting the bill impact associated with increased revenue responsibility for the class. Given the recent increases in revenue allocation and fixed charges for this rate class, the Department finds the proposed Customer Charge of $18.50 too aggressive. The Department approves a Customer Charge of $17.00, a more modest increase of $0.50 over CNG's present Customer Charge of $16.50. This Customer Charge represents approximately 40% of the unit cost of $42.81 derived by the COSS. Further, it increases the Company's fixed cost recovery by approximately $96,319 (192,637 bills x $0.50). The proposed Delivery Charge of $1.1500 per ccf will be adjusted to recover the allowed revenue for this rate class. The SSC will be calculated in accordance with Section II.K.4. SSC/TSC above.

b. Residential Heating

For Rate RSH, CNG proposed a monthly Customer Charge of $14.00, an increase of $1.00 over the current Customer Charge of $13.00. The proposed head block Delivery Charge was set at $0.8950 per ccf in the attempt to collect the remaining customer related charges not recovered through the monthly Customer Charge. Bill considerations also factored into CNG's proposed head block Delivery Charge. The proposed tail block Delivery Charge was set at $.2950, a sufficient level to collect the remaining revenue requirement for the customer class not collected in the Customer Charge and/or head block Delivery Charge. CNG set the Supply Charge at $0.9095 per ccf and the SSC at $0.0671 per ccf. CNG's proposal for Rate RSH results in an annual revenue recovery of $223,965,612, an increase of 1.63% over present revenues. Response to Interrogatory GA-2 Supplement, Exhibits I and V.

The Department believes that CNG's proposed customer charge of $14.00 is reasonable and therefore approves it. It represents approximately 30% of the unit cost of $46.61 derived by the COSS. The approved Customer Charge increases the Company's fixed cost recovery by approximately $1,525,838 (1,525,838 bills x $1.00). As a result of impending change in class revenues resulting from the instant Decision, the Company will adjust its Delivery Charges to collect any remaining revenue requirement for this class for Department approval in the Rate Design Plan. The SSC will be calculated in accordance with Section II.K.4. SSC/TSC above.

c. Residential Multi–Dwelling

CNG's proposal for Rate RMDS results in an annual revenue recovery of $20,361,488. CNG proposed the following charges for Rate RMDS: (a) to retain the monthly Customer Charge of $50.00; (b) Demand Charge of $0.4000 per ccf of demand, an increase of $0.3000 over the current $0.1000 Demand Charge; (c) declining block Delivery Charge head block of $0.3500 per ccf, and $0.1250 for tail block; (d) a Supply Charge of $0.8333 per ccf; (e) a SSC of $0.1000 per ccf; and (f) a

TSC of $0.0518 per ccf. Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit V.

The Department approves an increase of $5.00 to the Customer Charge for a total Customer Charge of $55.00. This is the amount the Company originally proposed in the Application. The approved Customer Charge represents approximately 43% of the unit cost of $127.60 derived by the COSS. A slightly more modest Demand Charge of $0.3000 is approved at this time as this charge had only been implemented for this class within the last year. Once the customers have had more experience with Demand Charges to understand the extensive cost savings available from peak day conservation, the charges for this class can be moved closer to full cost. The approved Customer and Demand Charge increase the Company's fixed cost recovery by approximately $453,257 [(19,071 bills x $5.00) + (1,789,512 ccf of demand x $0.20)]. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC above.

The Company also proposes to deploy daily demand metering (DDM) devices for all Rate RMDS customers. These customers historically have not been required to have DDMs for two reasons. First, until recently, Rate RMDS customers were not subject to a Demand Charge. Second, multi-dwelling properties were often subject to vandalism. The new technology, wireless DDMS, require only a small attachment to the existing meter and no phone line connection. Therefore the risk of vandalism is significantly lower. Further, daily usage information would now be available to these customers to assist with peak day management. This provides another conservation opportunity to a wider group of customers. The Company estimates that it would have approximately 1,520 Rate RMDS customers during the rate year. Late Filed Exhibit No. 47, Attachment 1. The proposed monthly DDM charge of $18.17 is pure cost based and grossed up for Residential GRT. The Company-proposed pro forma revenues of $346,520 related to DDMs for Rate RMDS. Therrien and Heintz PFT, p. 21, Response to Interrogatory GA-2, Attachment 1, Exhibit V.

The Company discussed the pros and cons of its proposal to require DDMs for all Rate RMDS customers with the alternative of using the current 500 Mcf annual throughput standard used for C&I customers. Out of 1,472 total Rate RMDS customers, the Company identified 963 Rate RMDS customers, or approximately 65%, that used more than 500 Mcf on an annual basis during the test year. The Company states that one of the drawbacks to having the DDM requirement only for customers that use more than 500 Mcf annually is the loss of daily consumption data for this group and the corresponding reduction in accuracy when setting their maximum daily quantity (MDQ) value. Another drawback is the additional administrative costs that would be required to create and maintain a Rate RMDS sub-group. The Company would need to identify the customers that would be exempt from the DDM requirement, monitor their exemption status at some regular frequency, and code them differently than other Rate RMDS customers for billing purposes. Additionally it would potentially require the addition and removal of DDM devices as customers exceed or fall below the 500 Mcf threshold. The Company offered a potential alternative to its original proposal, in which DDMs would be required only for Rate RMDS heating accounts. Non-heating accounts would be more likely to have a stable MDQ value than heating accounts. Further, the Company already differentiates these accounts in its internal rate code definitions. The positive result of the alternative is that it removes the expense of the DDM devices from the bills of the smallest customers in this rate class. Response to Interrogatory GA-376.

The Department extends to Rate RMDS its long standing DDM requirement for C&I customers with annual consumption greater than 500 Mcf. Customers above the annual threshold would benefit from daily consumption data as they have a greater ability to modify daily usage than those customers with lower annual consumption. For smaller customers, the possible cost savings from modifying peak day usage are much less than the costs associated with paying a monthly DDM charge. At the approved Demand Charge of $0.3000, the customer would have to reduce their peak day usage by approximately 61 ccf [$18.17 / $0.3000] just to break even with the $18.17 monthly DDM charge. This is simply not possible for most small Rate RMDS customers. As with Rate SGS customers, the algorithm used by CNG to determine the peak day usage for these customers is sufficient. Other than coding these customers differently for billing purposes, the Department sees no material change in how the Company handles these customers administratively.

As stated previously the Company identified that approximately 65% of its Rate RMDS customers used more than 500 Mcf on an annual basis during the test year. To calculate the pro forma adjustment, the Department applied the same factor to total pro forma customers to determine the approximate number of customers subject to a DDM requirement. Based on the Company's pro forma estimate of 1,520 RMDS customers during the rate year, approximately 988 [1,520 x 0.65] of these customers can reasonably be expected to have a DDM requirement. The Department approves pro forma revenue in the amount of $215,423 [988 x 12 x $18.17] related to the Rate RMDS DDM requirement during the rate year. This represents a decrease of $131,097 from the Company proposed revenues of $346,520.

6. Commercial and Industrial Services

The Company proposed further increases to its C&I Customer Charges to move closer to cost–based rates. The Company also states its proposed Demand Charges are set at full COSS unit rates for both Rates GS and LGS. Therrien and Heintz PFT, pp. 16 and 20. The proposed 100% COSS based customer and demand unit rates are as follows:

Rate	Customer	Demand
SGS	$79.74	$1.1648
GS	$161.22	$1.1415
LGS	$235.08	$1.1588

Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit VI.

The Department notes that the Demand Charge for Rates GS and the Customer Charge and Demand Charge for Rate LGS were set by the Company at less than the proposed 100% COSS-based rates. As discussed in Section II.J.3. <u>100% COSS Demand Charge</u>, the Department modified the Company's approach in favor of carrying the COSS derived demand charges forward to revenue exhibits without alteration, save GRT, making the statement "100% COSS rates" technically accurate.

a. Small General Service

CNG's proposal for Rate SGS results in an annual revenue recovery of $25,574,650. CNG proposed the following charges for Rate SGS: (a) a monthly Customer Charge of $42.00, which is a $4.00 increase over its current charge of $38.00; (b) a Demand Charge of $0.4000, an increase of $0.1000 over the current charge of $0.3000; (c) declining block Delivery Charges of $0.6720 per ccf up to the first 100 ccf of usage, and $0.2422 for each ccf thereafter; (d) a Supply Charge of $1.0926 per ccf; (e) a SSC of $0.0686 per ccf; and (f) a TSC of $0.0442 per ccf. Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit V.

The Department remains concerned about the negative rate impact that resulted from the direct assignment of high volume C&I customers out of Rate SGS as previously approved in Docket No. 06-03-04PH02. As a result, the Department believes that a $4.00 increase for the Customer Charge for Rate SGS is too aggressive, and believes that half of the proposed increase is more appropriate at this time. The Department approves a Customer Charge of $40.00 for Rate SGS, which is just over 50% of the unit rate of $79.74 derived by the COSS. The proposed Demand Charge increase is modest, and therefore approved without modification. The approved Customer Charge and Demand Charge increases the Company's fixed cost recovery by approximately $373,602 [(124,015 bills x $2.00) + (1,255,716 ccf of demand x $0.10)]. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC above.

b. General Service

CNG's proposal for Rate GS results in an annual revenue recovery of $37,394,485. CNG proposed the following charges for Rate GS: (a) a monthly Customer Charge of $95.00, which is an increase of $20.00 over its current charge of $75.00; (b) a Demand Charge of $1.1156, a slight decrease from its current Demand Charge of $1.1477; (c) declining block Delivery Charges of $0.2500 per ccf up to the first 300 ccf of usage, and $0.0795 for each ccf thereafter; (d) a Supply Charge of $0.8953 per ccf; (e) a SSC of $0.0922 per ccf; and (f) a TSC of $0.0491 per ccf. Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit V.

The proposed Rate GS Customer Charge of $95.00 is approved. The Demand Charge will be 100% cost-based as determined by the COSS submitted in support of the Rate Design Plan. The approved Customer Charge increases the Company's fixed cost recovery by approximately $749,640 (37,482 bills x $20.00). The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC above.

c. Large General Service

CNG's proposal for Rate LGS results in an annual revenue recovery of \$45,023,090. CNG proposed the following charges for Rate LGS: (a) a monthly Customer Charge of \$231.00, which is a decrease of \$24.50 from its current charge of \$255.50; (b) a Demand Charge of \$1.1358, a slight decrease from its current charge of \$1.1783; (c) declining block Delivery Charges of \$0.0795 per ccf up to the first 5000 ccf of usage, and \$0.0250 for each ccf thereafter; (d) a Supply Charge of \$0.7980 per ccf; (e) a SSC of \$0.1201 per ccf; and (f) a TSC of \$0.0418 per ccf. Response to Interrogatory GA-2 Supplement, Attachment 1, Exhibit V.

CNG's proposed class revenue for Rate LGS and resulting ROR of 24.75% remains significantly higher than the system average ROR of 11.22%. It is the highest ROR of all the rate classes. Id. The Department believes it is appropriate to reduce the proposed revenue allocation dramatically to reduce subsidization by this class. The Department approves a 100% cost-based Customer Charge and Demand Charge as determined by the COSS submitted in support of the Rate Design Plan. The Company will adjust its Delivery Charges to collect any remaining revenue requirement for the class for Department approval in the Rate Design Plan. The SSC and TSC will be calculated in accordance with Section II.K.4. SSC/TSC above.

7. Seasonal Gas Service

CNG alone offers a Seasonal Gas Service for residential (Rate SE-R) and commercial (Rate SE-C) customers with off-peak seasonal gas usage, primarily for equipment operated during the May through September billing period (Summer). Rate SE-R and Rate SE-C are value-of-service rates during the Summer, with the exception of the Customer Charge, and are filed annually by April 1 for Department approval. The rates for the off-season period, October through April (Winter), are not value-of-service rates and are set consistent with CNG's Rate RSG for Rate SE-R and Rate SGS for Rate SE-C.

CNG proposes to decrease the class revenue for both Rate SE-R and Rate SE-C. For Rate SE-R, CNG proposes to decrease the class revenue from \$174,453 to \$169,912, a decrease of \$4,541. For Rate SE-C, CNG proposes a class revenue decrease of \$32,499, from \$747,216 to \$714,717. CNG proposes no change to the Summer Customer Charge for both Rate SE-R and Rate SE-C. The proposed Winter charges for Rate SE-R and Rate SE-C are set in accordance with CNG's proposed charges for Rate RSG and Rate SGS, respectively. Late Filed Exhibit No. 1, Attachment 1, Exhibit V.

The Department approves CNG's proposed Summer Customer Charge for both Rate SE-R and Rate SE-C. The Summer Delivery Charge and Supply Charge will reflect the COSS submitted in support of the Rate Design Plan. However, the Winter Customer, Delivery, Supply Charges and the SSC should reflect the same charges that are approved for Rate RSG and Rate SGS on from which they are derived. Since the Department adjusted charges in Rate RSG and Rate SGS in the instant Decision, CNG must modify the applicable Rate SE-R and Rate SE-C charges, accordingly.

8. Summary of Rate Design Changes

The Department believes the approved charges herein builds upon the approved rate design from Docket No. 06-03-04PH02. Rate class revenue responsibility will be assigned in a fashion that reduces cross-subsidies between rate classes to the extent possible. Further, the Department approved increases in fixed charges for all rate classes that are not already at 100% cost based, thereby reducing intra-class subsidies and increasing fixed cost recovery by the Company. Yet to be quantified, customer and/or demand charges for Rates GS and LGS and will be set by the Company's COSS with its Rate Design Plan. Initial customer and demand charges approved in the instant Decision increase the Company's fixed cost recovery by approximately $3.2 million. Actual fixed cost recovery will not be known until the Company submits its Rate Design Plan. Increased fixed charges fulfill the requirements of § 107 Public Act 07-242 to decouple sales from revenue. The introduction of demand SSC and TSC rates also decouples sales from revenues and stabilizes gross margin recovery for the Company.

L. Maximum Daily Quantity

The MDQ is a determination of a customer's peak day consumption. In the Rate Design Decision, the Department concluded that CNG's tariffs were clear and unambiguous regarding the calculation of the MDQ. Further, it concluded that CNG was not calculating the MDQ accurately or in accordance with its tariffs. Rate Design Decision, p. 34. The failure to calculate the MDQ accurately or in accordance with its tariffs has ramifications for the instant rate case. When designing new rates, the demand charge listed on specific tariffs is multiplied by the aggregate billed MDQ for the tariff in question to determine demand charge revenue. If billed MDQs are misstated in this calculation, then demand revenue is also misstated. The resultant error in demand revenue is then built into other tariff charges, like customer or distribution, to collect the correct total revenue assigned to the rate class. Therefore, when MDQs are billed incorrectly, all other customers in that rate class are affected through their respective customer and distribution charges. Once rates are implemented, miscalculated MDQs result in an over or under collection of revenue by the Company.

To gauge the scope of the problem identified in the Rate Design Decision, the Department ordered CNG in the Rate Design Decision to file a MDQ analysis in the instant case. Order No. 20 was designed to calculate the revenue CNG did not collect during the test year. Further, Order No. 20 was based on the known facts as of issuance of that Decision on October 15, 2008, relating to improper calculation, billing and application of the MDQ and the associated demand charge. The Department explained in detail in that Decision how the revenue calculation was to be conducted.

In the instant case, CNG included a proposed positive revenue adjustment of $189,211 related to the specific revenue calculation pursuant to Order No. 20. Therrien and Heintz PFT; Revenue Proof Exhibits No. I-V. The Department's review of this compliance filing identified several additional problems associated with the Company's administration of its tariffs not contemplated when Order No. 20 was requested. Therefore, the Department issued Interrogatory GA-521 to determine the impact related to the additional problems discovered in Order No. 20. Specifically, the Department discovered that the scope of the problem was much broader than anticipated. In fact,