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ON BEHALF OF

OPTION CONSOMMATEURS

PRESENTED IN THE CASE OF

SOCIÉTÉ EN COMMANDITE GAZ MÉTRO'S APPLICATION

RELATIVE TO THE APPROVAL OF THE SUPPLY PLAN AND THE MODIFICATION

OF THE CONDITIONS OF SERVICE AND TARIFF

AS OF OCTOBER 1ST, 2012

FILE R-3809-2012

PHASE 1B

RÉGIE DE L'ÉNERGIE

DECEMBER 7th, 2012

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1. MANDATE

Following the filing by Société en commandite Gaz Métro (SCGM or Gaz Métro) of an application for approval of the Supply Plan and the modification of the Conditions of Service And Tariff, Option consommateurs (OC) retained our services in order to assist OC with its intervention before the Régie, and to produce an analyst report within the context of the case. In accordance with the calendar set out by the Régie on September 18, 2012, Phase 1 of the current hearing was divided in two parts ("Phase 1a" and "Phase 1b"). In Phase 1a, Econalysis Consulting Services (ECS) produced an analyst report, which covered the following hearing subjects:

1. The general acceptability of the overall Supply Plan in light of OC's interest in balancing security of supply with cost minimization;
2. The multipoint supply proposal and the strategy for displacement of the supply structure from Empress to Dawn;
3. The proposed rate modifications relative to interruptions.

In the Phase 1a hearings held in November 2012, OC also intervened on the subject of the Financial Derivative Program for Supply Hedging. On November 23, 2012, the Régie rendered a decision regarding Phase 1a of the current application (D-2012-158).

In accordance with the Régie's directives, the subject of the Performance Indicator for the Optimization of Supply Tools is being examined in the current phase of R-3809-2012 (i.e. Phase 1b). This subject is covered in the current analyst report.

2. INTRODUCTION AND CONTEXT

As Gaz Métro discussed at length in Phase 1a (in both its written evidence and the oral hearings), North American natural gas markets are undergoing a revolution, driven largely by the growth of supply from shale gas.[1] At the same time, natural gas production in the Western Canadian Sedimentary Basin is declining, while gas demand in the West is increasing due to the expansion of the Tar Sands and LNG gas projects in British Columbia. In this context, the price differential between Empress and Dawn has decreased significantly in recent years and this differential is now lower than the TCPL transmission rate. Gaz Métro concludes that this trend will be maintained in the future and that it is more economical to buy gas directly at Dawn rather than to buy it at AECO and have it transported eastward.[2] In Phase 1a, Gaz Métro's witnesses emphasized repeatedly that it is more economical to shift its gas supply structure closer to Quebec. Moreover, Gaz Métro stressed that this shift has the further advantage of decreasing reliance on TCPL, which is facing severe competitive challenges.

OC agreed with Gaz Métro's assessment in Phase 1a that there is a revolution underway in the North American natural gas markets driven largely by the shale gas boom. According to our Phase 1a analyst report (C-OC-0010):

> This revolution has particularly strong effects on gas markets in Quebec, Ontario, and the Northeastern US. And this revolution is impacting Gaz Métro in a number of ways. These changes are ongoing, likely to continue, and may in fact be intensifying and accelerating. (p. 4, lines 13-16)
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> […]
>
> Business as usual is not a viable option during a revolution; prudent management requires that Gaz Métro respond to these profound changes in the markets and its operating environment. (p. 5, lines 9-11)

[1] B-0031 (GM-1, Doc 1), Section 1, pp. 12-26; B-0034 (GM-1, Doc 16), Section 6.4.2, pp. 32-34.
[2] B-0031 (GM-1, Doc 1), p. 25, lines 16-29.

As such, OC provided conditional support for Gaz Métro's Supply Plan in Phase 1a and concluded that despite the sizable uncertainties and risks associated with the shifts proposed by Gaz Métro, the Supply Plan appeared to balance security of supply with cost minimization; and to be generally favourable to consumers. Regarding the displacement of the supply structure to Dawn, OC observed that it appears that the displacement to Dawn is a prudent response to the current context (including the shale-driven revolution in the natural gas markets and other current conditions). This context, characterized by risks and opportunities and costs and benefits, is also relevant to Gaz Métro's proposed Performance Indicator, which will be reviewed in the following sections.

3. OC'S POSITION ON GAZ MÉTRO'S PROPOSAL FOR A PERFORMANCE INDICATOR FOR THE OPTIMIZATION OF SUPPLY TOOLS

3.1. OC'S POSITION ON INCENTIVE MECHANISMS

At the outset, we wish to emphasize that we do not oppose well-structured incentive mechanisms. Indeed, a mechanism that delivers strong incentives can lead to improved performance on the part of the Distributor and can lighten the regulatory burden for all participants in the regulatory process. Well-structured incentive mechanisms can provide benefits to both the Distributor and to customers. Indeed, OC has been a signatory of Gaz Métro's incentive mechanism negotiation settlements (*PEN*) for over a decade. Going forward, OC will support well-structured incentive mechanisms that provide equitable sharing of awards and penalties between customers and the Distributor; and are based on best practices and lessons learned from experience to date with incentive mechanisms throughout North America.

Time and resources did not allow us to conduct an exhaustive review of best practices in incentive mechanism design for gas distributors. However, a literature review yielded two highly relevant (and related) articles:

1. "A Hard Look at Incentive Mechanisms for Natural Gas Procurement" by Ken Costello and James F. Wilson, the National Regulatory Research Institute, November 2006.[3]

2. "Natural Gas Procurement: A Hard Look at Incentive Mechanisms" by Ken Costello and James F. Wilson, Public Utilities Fortnightly, February 2006;[4]

The first and longer article ("NRRI GPIM article"), published by the National Regulatory Research Institute, is filed as Appendix 1 to the current report. The second article ("PUF GPIM article"), published in Public Utilities Fortnightly, is a shorter version of an earlier draft of the first article.

The articles are based on an extensive and thorough review of multiple GPIMs (Gas Procurement Incentive Mechanisms) throughout the US, "of documents representing reviews of GPIM results, and of regulatory commission orders approving the associated rewards" (PUF GPIM article, p. 46).[5] While many of the GPIMs reviewed in the articles provide incentives "for all, or nearly all procurement-related costs", the NRRI article recognizes "that some utilities have incentives only for commodity purchases, while others have incentives confined to off-system sales and capacity releases" (NRRI GPIM article, p. 5). The articles take into account a wide variety of potential incentives and as such, pitfalls and lessons learned from the articles are relevant to Gaz Métro's Performance Indicator, which applies only to transportation and load-balancing costs.

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[3] www.nrri.org/pubs/gas/06-15.pdf also filed in Appendix 1 of this Report.
[4] www.fortnightly.com/fortnightly/2006/02/natural-gas-procurement-hard-look-incentive-mechanisms
[5] The Appendices in the NRRI GPIM article include: Summary of Structures of Gas Procurement Incentive Mechanisms for 15 gas distributors (Appendix 1); Summary of Structures of Gas Portfolio and Asset Management Agreements for three gas utilities (Appendix 2); Links to Gas Procurement Incentive Mechanisms, which are mostly outdated, but which provide a list of 27 gas distributors with GPIMs in 2006 (Appendix 3); Arithmetic of Gas Procurement Incentive Mechanisms (Appendix 4), which provides an arithmetic description of a generic benchmark incentive mechanism; Examples of Issues and Problems Raised in Regard to Gas Procurement Incentive (Appendix 5). Of the 11 gas distributors discussed in Appendix 5, seven had problems related to sharing and the asymmetry of benefits and rewards (typically in favour of the distributor).

The Executive Summary emphasizes the key finding that poorly structured GPIMs, which fail to create true incentives, are quite common (our underlining):

> This paper finds that existing GPIMs take a wide variety of forms across the country, differing in the scope of incentives, the approach to forming a benchmark, and the quality of the resulting incentives, among other characteristics. While some GPIMs are well-structured, design characteristics that result in weak or distorted incentives for some gas procurement decisions are quite common, with many GPIMs affording opportunities for the utility to increase its incentive award while not reducing, or even increasing, the customers' gas cost. (NRRI GPIM article, Executive Summary).[6]

The NRRI GPIM article reviews and assesses approaches to the design of GPIMs; and describes "some of the most common characteristics found in GPIM designs that compromise the incentives provided, create gaming opportunities, and/or lead to larger company awards even if performance is not better than would be expected without incentives" (p. 9).[7] The discussion of common pitfalls then suggests "design principles that lead to strong and undistorted incentives that align utility and customer interests" (p.

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[6] The Executive Summary (NRRI GPIM article, p. 1) goes on to conclude the following from Costello and Wilson's findings (our underlining):

Incentive mechanisms providing strong incentives properly aligned with customers' interests can reduce the need for detailed regulatory review of the procurement function, as a well-structured incentive mechanism's awards and penalties impose appropriate consequences for superior or inferior performance. However, to the extent a GPIM provides weak or no incentive for some aspects of procurement decision-making, a traditional review of these aspects remains appropriate. Moreover, to the extent an incentive mechanism provides distorted incentives and gaming opportunities, a more detailed and focused review would be needed to determine whether any abuse had occurred.

Our review of existing GPIMs indicates that very few are sufficiently broad and well-structured to eliminate the need for regulatory review of procurement decision-making. Yet in most instances, the regulatory reviews of GPIM results and of procurement decisions amount to little more than an audit of the utility's actual costs and incentive award calculations. The limited scope of the reviews in some cases suggests that the regulatory staff responsible for the reviews may not be aware of the incentive mechanism's shortcomings and the resulting weak incentives and gaming opportunities.

Finally, we also observe that the common measure of GPIM "savings" and customer benefits, based on the difference between a utility's actual gas costs and a GPIM benchmark, often provides an inaccurate (and overly positive) measure of utility performance and the impact of the GPIM. For many GPIMs, the benchmark is a simplified formula that is easy to beat without superior performance, and in some instances, the utility can raise the benchmark through its actions, creating a distorted measure of savings and benefits.

[7] See pp. 8-15 of NRRI GPIM article for the description of 10 Common Pitfalls in GPIM Design and Structure with special attention to pitfall #2 (Benchmarks that are too easy to beat) and pitfall #9 (Sharing rules providing asymmetric awards and penalties).

15).[8] The summary recommendations for GPIM Design Principles and Characteristics are listed in a box on p. 17. See in particular Recommendations 4, 6 and 7 (4. Define the Benchmark to Approximate a Reasonable Strategy – Not Too Easy to Beat; 6. Set Sharing Rules to Provide Strong, Symmetric Incentives under All Conditions; 7. Meanwhile, Try To Keep It Simple).

While the articles are six years old, their conclusions are still relevant. In particular, the common pitfalls and recommendations identified represent lessons learned from a first generation of GPIMs. These are pitfalls that should not be repeated as we move towards new incentive mechanisms. Unfortunately, as will be discussed in the next Section, Gaz Métro's proposed mechanism is characterized by a number of the common pitfalls identified by Costello and Wilson, without achieving some of the key design objectives for well-structured incentives set out in the articles.

3.2. PERFORMANCE INDICATOR FOR OPTIMIZATION OF SUPPLY TOOLS (2014-2018)

OC does not support the proposed Performance Indicator for Optimization of Supply Tools for the following reasons:

1. The proposed sharing rules provide asymmetric awards and penalties; such asymmetry is inequitable towards consumers and provides a distorted incentive for risk-taking;

2. The proposed 2010 benchmark is too easy to beat, such that Gaz Métro need not achieve superior performance to earn a bonus;

3. The proposed 2010 benchmark amounts to a retroactive reward for actions that have already been undertaken (and approved by the Régie) to optimize the supply structure (notably the actions put in place to displace the supply structure to Dawn, approved by the Régie in D-2012-158);

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[8] See pp. 15-17 of NRRI GPIM article for GPIM Design: Summary and Recommendations.

4. The proposed Performance Indicator has the potential to increase the regulatory burden (as evidenced so far in this case) for very modest objective savings (as shown when performance is compared to a more reasonable benchmark). Ratepayers, particularly in the D1 class, will support the costs of the Performance Indicator, as well as the undue regulatory burden of reviewing this Performance Indicator.

5. The proposed allocation of the Performance Indicator by rate class has a much higher incidence on D1 consumers in general than on the other rate classes.

Sections 3.2.1 to 3.2.5 will further elaborate on each of the five reasons why the Performance Indicator for Optimization of Supply Tools should be rejected by the Régie.

3.2.1. Sharing Rules Provide Asymmetric Awards and Penalties

The proposed sharing rules provide asymmetric awards and penalties; such asymmetry is inequitable towards consumers and provides a distorted incentive for risk-taking. Gaz Métro is proposing a bonus for overearnings (*trop-perçus*) related to value created in its transmission (*transport)* and load-balancing (*équilibrage*) services, as set out in Table 5 of B-0111 (GM-4, Doc 1), p. 22. The proposed bonus would have a $5 million cap. Conversely, the Distributor is emphatic that it <u>will not accept any penalty</u> with respect to underearnings (*manques-à-gagner*) in its transmission and load-balancing services. In response to IR 5.1 by the Régie (B-00113 (GM-5, Doc 14), p. 14) concerning the annual or cumulative penalties that Gaz Métro would be ready to accept, as appropriate, the Distributor answers as follows:

> *Le mécanisme proposé pour l’indicateur retenu ne prévoit pas de pertes annuelles ou cumulatives pour Gaz Métro. Gaz Métro n’est pas prête à accepter de risquer des pertes monétaires en transport et en équilibrage.*
>
> *[…]*
>
> *Dans l’éventualité où la Régie ne serait pas prête à accorder à Gaz Métro une possibilité de générer une bonification reliée à son plan d’approvisionnement sans le risque éventuel d’encourir des pertes, Gaz Métro soumet*

respectueusement que la seule option à considérer serait d'appliquer uniquement un coût de service pour le transport et l'équilibrage avec des trop-perçus et manques à gagner à 100 % à la charge des clients. [9]

Gaz Métro's answer to Régie IR 5.1 demonstrates its intransigence with respect to symmetric sharing of costs and benefits. It further convinces us that customers are better off under a cost of service (COS) regime in which they assume 100% of overearnings and 100% of underearnings in the transmission and load-balancing services. The asymmetric alternative offered by the Performance Indicator is to assume 100% of overearnings and 100% of underearnings AND pay Gaz Métro a bonus in addition to this.

As indicated in Section 3.1, "Sharing rules providing asymmetric awards and penalties" was identified by Costello and Wilson in the NRRI GPIM Article as one of the Common Pitfalls in GPIM Design and Structure, which compromise the incentives provided. According to the NRRI article (p. 15), "some GPIMs provide awards but not penalties. Such an asymmetry provides a distorted incentive for risk-taking." In the list of Recommended GPIM Design Principles and Characteristics, in the same article (p. 17), Costello and Wilson recommend the following:

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[9] We are surprised by flawed reasoning in the first part of Gaz Métro's answer to this same IR, in which the Distributor justifies its position not to accept any penalties for transmission or load-balancing services (p. 1):

Cette position s'explique par le fait que Gaz Métro ne contrôle pas l'environnement associé au transport, encore plus particulièrement, dans un contexte en mouvance. Contrairement à la distribution où elle exerce un contrôle plus accentué sur ses coûts, par exemple sur ses salaires ou ses dépenses, les coûts de transport sont tributaires du contexte gazier du moment (sur une base relative) sur lesquels Gaz Métro exerce moins de contrôle. Les impacts des aléas climatiques et l'incertitude des transactions financières peuvent constituer des exemples qui entraîneraient des variations à la valeur créée qui sont hors du contrôle de Gaz Métro.

Gaz Métro est d'avis qu'il serait inéquitable qu'elle ne puisse recouvrer son coût de service en raison d'une décision de la Régie lui imposant un incitatif susceptible de lui faire subir une perte à cause de circonstances échappant en partie à son contrôle.

Gaz Métro maintains that its position not to accept a penalty for underearnings is explained by the fact that it does not control the environment associated with transportation, especially during a period of change. If Gaz Métro does not control its environment enough to influence outcomes, then it should not receive a bonus for overearnings. Or if in fact Gaz Métro can optimize its transportation and load-balancing activities as it has claimed elsewhere, then the bonuses and penalties should be symmetrical. The Distributor cannot have it both ways.

Set Sharing Rules to Provide Strong, Symmetric Incentives Under All Conditions: The sharing rules should be set to balance the strength of incentives, the likelihood of relatively large deviations between actual and benchmark gas costs, the utility's risk attitude, and other factors. Variable or asymmetric sharing rules, tolerance bands, and caps distort and blunt incentives, and should be avoided.

Gaz Métro's proposed sharing rules for the Performance Indicator contravene Costello and Wilson's recommendations, are inequitable towards consumers and provide a distorted incentive for risk-taking.

3.2.2. The Benchmark is Too Easy to Beat

The proposed 2010 benchmark is too easy to beat, such that Gaz Métro need not achieve superior performance to earn a bonus. This results in an inequitable transfer of wealth from consumers to the Distributor. In both its written evidence and particularly in its oral testimony, Gaz Métro devoted significant energy in Phase 1a of this case to convincing us that moving the supply structure closer to its service territory would result in lower costs. And this is particularly true for transportation costs because Dawn is much closer than Empress.

Between 2010 and 2012, Gaz Métro began the process of optimizing purchase locations (to purchase more gas at Dawn, thus decreasing purchases at Empress and incurring significant savings on transportation). With the displacement of the supply structure to Dawn, now scheduled to begin in November 2015, the optimization of purchase locations will be significantly strengthened.

Therefore the choice of 2010 represents a benchmark that is too easy to beat and will be easily beaten every year of the proposed Performance Indicator regime (2014-2018). This choice of benchmark does not provide a sufficient incentive for stronger performance over the period of the Performance Indicator. Instead, it guarantees an award to Gaz Métro for its prudent <u>past</u> management decisions to optimize its supply structure. And as of 2016 onward (when the supply structure is moved to Dawn), Gaz Métro's bonus will increase dramatically (and quite possibly right to the $5 million cap) –

not due to superior performance in 2016; but simply due to the fact that the 2010 benchmark does not reflect the deep changes in the optimization of purchase locations. If the $5 million cap is achieved after the displacement to Dawn, the indicator will fail to provide any incentive at all for better performance as long as the benchmark is set at 2010.

As indicated in Section 3.1, "Benchmarks that are too easy to beat" was identified by Costello and Wilson in the NRRI GPIM Article as one of the Common Pitfalls in GPIM Design and Structure, which compromise the incentives provided. According to the NRRI article (p. 9) (our underlining):

> <u>A common GPIM characteristic is a benchmark that is easy to beat, so the utility need not achieve superior performance to earn an award.</u> The benchmark might be highly simplified or inflexible in some respects and, as a result, represents a level of cost and implied procurement strategy that under many circumstances, if subjected to a reasonableness review, would likely be found imprudent. <u>For instance, the benchmark might not reflect optimization of purchase locations</u>, or it might include low expectations (or no expectations) with respect to revenues from release of unneeded capacity, or it might assume the utility must pay full transportation tariffs when discounting is common, to note a few examples.
>
> <u>Note that even if the utility achieves superior performance relative to what would have been expected under traditional regulation, if a benchmark is too easy to beat, consumers can be harmed and end up paying more.</u>

In the list of Recommended GPIM Design Principles and Characteristics, in the same article (p. 17), Costello and Wilson recommend the following:

> <u>**Define the Benchmark to Approximate a Reasonable Strategy – Not too Easy to Beat:**</u> Avoid rigid assumptions about purchase locations; include estimates of offsetting revenues from capacity release and off-system gas sales, etc.

Gaz Métro's proposed 2010 benchmark year falls squarely into one of Costello and Wilson's classic pitfalls (by not reflecting the optimization of purchase locations) and contravenes their related recommendation to define a benchmark that is "not too easy to beat."

Gaz Métro's answers to IRs from OC[10] and the Régie support the conclusion that the 2010 benchmark is too easy to beat.

The Distributor's responses to the OC IRs (B-0116, GM-5, Doc 17, IRs 3.1 and 3.2 (pp. 6-9) and IRs 4.2, 4.3, 4.4, 4.5 (pp. 10-14)) demonstrate that over the first two years of the Performance Indicator (scheduled in the revised proposal for 2014 and 2015), the calculated "created value" and the related bonus remain quite flat with almost identical value created in 2014 and 2015 and almost identical corresponding bonuses. So we can conclude that almost no incremental value would be created between 2014 and 2015. There appears to be an increase in created value of about 9.2% between the 2013 and 2014 results.[11]

Gaz Métro's response to IR 8.2 by the Régie (B-0113, GM-5, Doc 14, pp. 20-22) offers even stronger evidence that the 2010 benchmark is too easy to beat. The Régie asks to set the benchmark at 2012 and asks to calculate the value created under the Performance Indicator for the year 2013. With a benchmark of 2012, the created value

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[10] OC's IRs (B-0116, GM-5, Doc 17, IRs 3.1 and 3.2 (pp. 6-9) and IRs 4.2, 4.3, 4.4, 4.5 (pp. 10-14) attempted to evaluate the evolution of the bonus levels over the period of the application of the Performance Indicator. Given that Gaz Métro's original proposal did not document the period of application of the Indicator, we assumed that this period would be 2013-2015. Because the displacement of the supply structure to Dawn was scheduled for November 1, 2014, we expected to be able to track a significant increase in bonus level in the 2015 results.

We now know that the revised Performance Indicator proposal covers the five-year period of 2014-2015; and that displacement of the supply structure to Dawn has been delayed until November 1, 2015. Given that our IRs did not cover the last three years of the Indicator, i.e. 2016-2018, we are not in a position to evaluate exactly how high the bonus will go. However, the original Table in B-0016 (GM-1, Doc 12), p.1, columns 5 and 6, shows the savings that would have occurred if the displacement of the supply structure had gone ahead as scheduled on November 1, 2014. Although Gaz Métro did not provide a clear explanation of how the numbers in B-0016 relate to the bonus calculations (response to OC IR 6.1, B-0116, p. 18), it is reasonable to assume based on the dramatic increases in savings shown in columns 5 and 6 of the Table in B-0016 that the bonuses in 2016-2018 will increase considerably and could possibly reach the $5M cap.

[11] We note from the tables in response to OC IRs 3.1 and 3.2 that there is a 9.2% increase in the "created value" between 2013 and 2014 and a 18.6% increase in the bonus between these two years, which demonstrates that the progressive bonus mechanism results in substantial bonus increases at some levels. However, 2013 is not subject to the Performance Indicator in the current proposal.

is only $425,424 vs. $99,571,988 using a benchmark of 2010 for the same year (2013).[12] According to the bonus calculation, the amount of created value with a benchmark of 2012 would not even warrant a bonus.

The response to Régie IR 8.2 demonstrates that there is very little new value created between 2012 and 2013. What is driving the "created value" of almost $100 million for 2013 (in the response to OC IR 3.1) is the use of the 2010 benchmark that does not reflect the optimization of purchase locations that took place between 2010 and 2012.

Although it would be tempting to use 2012 as a benchmark (and indeed, it would likely be a more realistic benchmark than 2010), 2012 does not fully reflect the optimization of purchase locations because the displacement of the supply structure to Dawn will not take place until November 2015. Therefore, the "created value" as measured by the Performance Indicator will then spike again. The response to Régie IR 8.2 (vs. OC IR 3.1) provides strong numerical evidence that the 2010 benchmark is too easy to beat; does not provide incentive for superior performance; and results in inequitable transfer of wealth from consumers to utility.

3.2.3. The Benchmark Amounts to a Retroactive Reward for Actions Already Undertaken

The choice of a 2010 benchmark amounts to a retroactive reward for actions that have already been undertaken (and approved by the Régie) to optimize the supply structure (notably the actions put in place to displace the supply structure to Dawn approved by the Régie in D-2012-158). An incentive mechanism should apply to actions <u>going forward</u> (i.e. undertaken in the year of application of the mechanism) and should not constitute a retroactive reward. According to the PUF GPIM article (p. 43), "[t]he objective of most GPIMs is to provide incentives for achievement of lower short-term procurement costs." GPIMs do not attempt to "provide incentives with respect to

[12] B-0113, Response to Régie IR 8.2, Table 4, p. 22; B-0116, Response to OC IR 3.1, p. 6.

decisions concerning long-term firm pipeline and storage reservations, which usually are reviewed and approved separate from a GPIM."

The choice of the 2010 benchmark handsomely rewards Gaz Métro for actions already undertaken to optimize its locational purchases, which were made between 2010 and 2012 and involved decisions concerning long-term pipeline and storage reservations, and which have already been reviewed and approved by the Régie. As explained in the previous section (3.2.2), these handsome rewards will increase considerably in 2016, when the supply structure is displaced to Dawn. With a benchmark of 2010, which does not reflect the deep changes in optimization of purchase locations resulting from the displacement of the supply structure to Dawn, the Performance Indicator will provide even higher rewards in the last three years of the proposed five-year mechanism (i.e. 2016, 2017, 2018).[13]

As stated in Section 2, OC has been supportive of decisions undertaken by Gaz Métro from 2010-2012 regarding the optimization of purchase locations and the shift of the supply structure to Dawn. In Phase 1a, we have observed that the shift to Dawn is a prudent response to the current context and constitutes prudent management on the part of Gaz Métro. However, Gaz Métro has already been paid for this prudent management (through the Régie-approved Return on Equity (ROE) and through recovery of costs to provide this prudent management). It defeats the purpose of an incentive mechanism to structure the Performance Indicator in such a way as to reward Gaz Métro for decisions that have already been made and approved, and for which Gaz Métro has already been paid. The Performance Indicator should constitute an incentive

[13] In the last section (3.2.2), we discussed how a 2012 benchmark would be a more realistic benchmark than 2010. A 2012 benchmark would likely reduce large overestimates in the "created value" for 2014 and 2015 (using a benchmark of 2010). The inflated "created value" and corresponding generous bonuses amount to retroactive rewards for decisions taken to optimize purchase locations between 2010 and 2012. Still, as explained in the last section, a benchmark of 2012 does not fully reflect the optimization of purchase locations because the displacement of the supply structure to Dawn will not take place until November 2015. Thus, although a 2012 benchmark is an improvement on 2010, it will likely still result in inflated "created value" from 2016-2018 and a portion of the corresponding bonuses will be retroactive rewards for past decisions.

for superior performance in the year the indicator is being applied. The Indicator should not be a retroactive reward for past performance no matter how laudable.

OC has already given its conditional support for Gaz Métro's prudent management during the current revolution in North American natural gas markets. However, we do not believe that the Distributor deserves a five-year retroactive reward for prudent management.

3.2.4. Regulatory Burden May Be Increased

The proposed Performance Indicator has the potential to increase the regulatory burden (as evidenced so far in this case)[14] for very modest objective savings (when performance is compared to a more reasonable benchmark).[15] Ratepayers, particularly in the D1 class, will support the costs of the Performance Indicator, as well as the undue regulatory burden of reviewing this Performance Indicator.

As cited in Section 2 (footnote 6), Costello and Wilson have pointed out that poorly structured GPIMs characterized by distorted incentives and gaming opportunities, can increase regulatory burden (NRRI GPIM article, p. 1):

> Incentive mechanisms providing strong incentives properly aligned with customers' interests can reduce the need for detailed regulatory review of the procurement function, as a well-structured incentive mechanism's awards and penalties impose appropriate consequences for superior or inferior performance. However, to the extent a GPIM provides weak or no incentive for some aspects of procurement decision-making, a traditional review of these aspects remains appropriate. <u>Moreover, to the extent an incentive mechanism provides distorted</u>

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[14] An inadequately documented Performance Indicator proposal was submitted in July 2012 (B-0023), which led to a large number of interrogatory requests due to the lack of documentation and transparency of the original proposal. This in turn resulted in the R-3809-2012 Phase 1 being split into two phases (1a and 1b) and a significant lag in the regulatory process for the 2012-2013 rate case, as well as transaction costs involved in holding separate hearings and in the delays involved in the process. A revised proposal was then filed (B-0111) on November 16, as well as a separate document describing the Performance Indicator, *Document Descriptif* (B-0113, GM-5, Doc 14, Annexe).

[15] According to Gaz Métro's response to IR 8.2 by the Régie (B-0113, GM-5, Doc 14, pp. 20-22) when a more realistic benchmark of 2012 was used to calculate the value created in 2013, it was only $425,424. The regulatory burden required in Phase 1b alone may well exceed this amount.

> incentives and gaming opportunities, a more detailed and focused review would be needed to determine whether any abuse had occurred.
>
> Our review of existing GPIMs indicates that very few are sufficiently broad and well-structured to eliminate the need for regulatory review of procurement decision-making.

A central objective of an incentive mechanism is to reduce the regulatory burden and oversight. So an increase in said burden defeats a key purpose of the Performance Indicator. Given the inefficiency of the regulatory process so far, the approval of the proposed Performance Indicator has already increased the regulatory burden. More importantly, the serious design problems noted above (particularly related to asymmetrical sharing, a benchmark that is too easy to beat and provides handsome retroactive rewards) all give rise to distorted incentives that favour the Distributor. As such, it is quite possible that the Performance Indicator will result in an increase, and not a decrease, of the regulatory burden over the period of its application.

3.2.5. The Allocation of the Performance Indicator by Rate Class Has Highest Incidence on D1 Customers

The proposed allocation of the Performance Indicator by rate class has a much higher incidence on D1 consumers than on the other rate classes. This is demonstrated in Gaz Métro’s response to OC IR 1.2.1 (B-0015, GM-5, Doc 17, pp. 2-4). In Gaz Métro’s example (using data from the 2012 Rate Case), D1 customers make up 46.5% of the total customer volume and pay 65.4% of the bonus. Blocks D1.1-D1.3 (which comprise most of the residential customers) make up 6.9% of the total customer volume and pay 10.2% of the bonus. Many low-income customers, who are bulk-metered (*utilisateurs non-clients*) are indirectly subject to the higher volume D1 commercial rates. Our analysis, based only Gaz Métro’s example, indicates that D1 customers, both large and small, will pay a larger share of the Performance Indicator than non-D1 customers.

Moreover, if the bonus increases as expected over the five year span of the proposed mechanism, D1 consumers will bear an increasingly heavy cost for the bonus. Furthermore, other large customer classes, which are less captive than D1 consumers (and particularly residential consumers) can opt to provide their own transportation services as the price of transportation is pushed up by increasing bonuses. This could result in fewer customers paying a larger and larger share of the bonus.

OC understands that the example provided by Gaz Métro in the response to OC IR 1.2.1 (B-0015, GM-5, Doc 17, pp. 2-4) is based on cost allocation for the Performance Indicator as set out in the *Document Descriptif* (B-0113, GM-5, Doc 14, Annexe, p. 17). While we are not maintaining that the cost allocation is inappropriate, it is not clear that this is the correct cost allocation either; and we believe that the allocation of the bonus may necessitate further review. The high incidence of the Performance Indicator on the D1 class is illustrative of the fact that proper and equitable design of a Performance Indicator is complex and should be well-considered. Based on the Distributor's proposal and its IR responses, we are not convinced that Gaz Métro has given the design of the indicator the deliberation it deserves.

3.3. EXTENSION OF THE PROVISIONS OF THE EXPIRED INCENTIVE MECHANISM FOR THE OPTIMIZATION OF FINANCIAL TRANSACTIONS (2013)

For 2013, Gaz Métro is proposing to extend the provisions of the recently expired Incentive Mechanism relative to sharing for the optimization of financial transactions (as per Section 3.2.2 of *Mécanisme incitatif convenu par le groupe de travail à la phase 2 du PEN*, R-3599-2006) (B-0111, GM-4, Doc 1, p. 24, lines 1-4).

OC recommends that the Régie reject this proposal for the following reasons:

1. The proposed sharing rules (i.e. 25% of overearnings to Gaz Métro and 75% to the customers; 100% of underearnings to the customers) provide asymmetric awards and penalties; such asymmetry is inequitable towards consumers and provides a distorted incentive for risk-taking. We note that the Régie also asked what advantage customers may derive from this asymmetrical sharing (B-0113, GM-5, Doc 14, Régie IR 13.3 to Gaz Métro, p. 36). In response to the Régie's IR, Gaz Métro fails to provide a convincing answer. Section 3.2.1 above discusses

the problems with asymmetric sharing relative to the Performance Indicator. In that section, we have cited relevant extracts from the Costello and Wilson articles regarding the pitfalls of asymmetric sharing and the importance of setting sharing rules to provide strong, symmetric incentives under all conditions.

2. We question the validity of extracting the provisions relative to sharing for the optimization of financial transactions from an expired Incentive Mechanism that was negotiated as a package. We note that the Régie also asked about this issue. In Régie IR 13.1 to Gaz Métro (B-0113, GM-5, Doc 14, p. 35), the Régie asks the Distributor to justify how the maintenance of the sharing terms relative transportation and load-balancing was justifiable in isolation without the other terms of the Incentive Mechanism. In response to the Régie's IR, Gaz Métro fails to provide a convincing answer.

3. The proposed extension of the provisions of the recently expired Incentive Mechanism also increases the regulatory burden by setting up a mechanism for just one year. As discussed in Section 3.2.4, a central objective of an incentive mechanism is to reduce the regulatory burden and oversight. This proposal appears to the do the opposite.

4. RECOMMENDATIONS

4.1. Gaz Métro's Proposals Should be Rejected

For all the reasons presented above, we strongly recommend that the Régie reject both (a) the Performance Indicator (proposed for 2014-2018); and (b) the extension of the provisions of the recently expired Incentive Mechanism relative to the optimization of financial transactions (proposed for 2013). Gaz Métro has failed to meet its burden of proof to demonstrate that the proposals are well-structured incentive mechanisms that will lead to superior performance while lightening the regulatory burden, thus providing benefits to both customers and the Distributor.

Our assessment is that the proposed Performance Indicator is deeply flawed (for the five key reasons discussed in Section 3.2); and contravenes two key recommendations from Costello and Wilson for GPIM Design Principles and Characteristics: (a) set sharing rules to provide strong, symmetric incentives under all conditions; and (b) define the benchmark to approximate a reasonable strategy – not too easy to beat. Moreover, the Performance Indicator fails to deliver on the central objectives of most GPIMs: to provide true incentives for the achievement of lower short-term costs; and to reduce the regulatory burden. These flaws would result in the transfer of millions of dollars in unjustified awards from ratepayers (and mainly D1 customers) to Gaz Métro shareholders. Moreover, ratepayers would also have to pay for the outsized regulatory burden accompanying this transfer of wealth.

Similarly, the proposal to extend the provisions of the recently expired Incentive Mechanism relative to sharing for the optimization of financial transaction for 2013 is also flawed and should be rejected for the reasons discussed in Section 3.3.

4.2. Guidelines Regarding the Development of an Alternative Proposal for a Performance Indicator to Optimize Supply Tools

Given the extent of the flaws identified in the two proposals, these proposals do not lend themselves to a few simple modifications and amendments. As such, we have not developed an alternative proposal for a Performance Indicator, but we suggest some guidelines.

4.2.1. Consider Delaying the Implementation of a Performance Indicator until After the Displacement of the Supply Structure to Dawn

We recognize that it is challenging to develop a well-constructed Performance Indicator that achieves the key objectives of delivering incentives for improving performance and reducing the regulatory burden while providing equitable sharing of awards and penalties between the customers and the Distributor.

These challenges are exacerbated in the middle of a revolution in the North American gas markets. Gaz Métro has discussed this revolution at length in its Phase 1a filing and testimony. Moreover, when justifying why it could not accept a penalty for underearnings in the Performance Indicator, the Distributor evokes the *contexte en mouvance* (see Response to IR 5.1 by the Régie (B-00113 (GM-5, Doc 14), p. 14)) and footnote 9. If it is too risky for Gaz Métro to accept a penalty in this revolutionary period, it is also too risky for the customers to allow the Distributor to only receive bonuses.

The Régie may wish to apply a Cost of Service regime for supply until conditions stabilize and the displacement to Dawn has been completed. Since 2016 is the first year of the displacement to Dawn, Gaz Métro may want to consider setting a benchmark of 2016 and starting the application of the Performance Indicator in 2017. Alternatively, it may be possible to create a benchmark prior to 2016, which reflects the optimization of the purchase locations (i.e. the displacement of the supply structure to Dawn), but this may be overly complex in the absence of real data reflecting the shift to Dawn.

4.2.2. Consideration of the Performance Indicator as Part of a Global Incentive Mechanism

Given that the Performance Indicator has to be reconsidered in order to deliver on the key objectives of an incentive mechanism, there are some advantages to implementing it as part of broader Incentive Mechanism, which includes gas distribution. This is a good way to avoid creating perverse or distorted incentives (especially for interrelated costs and revenues), and to ensure that a future global Incentive Mechanism can be applied as a coherent whole. Given that an application for R-3693-2009 Phase 3 was filed at the end of November 2012, it is likely too late to consider the Performance Indicator as part of Phase 3. However, consideration of a Performance Indicator for the Optimization of Supply Tools could be included in the next renewal of the Incentive Mechanism for gas distribution.

4.2.3. Hire an External Expert to Assist Gaz Métro in the Development of a New Performance Indicator

In Section 2.8 of the *Document Descriptif* (B-0113, GM-5, Doc 14, Annexe, pp. 9-10), Gaz Métro suggests that an external expert should be appointed by Régie to evaluate the Performance Indicator after the third complete year of its application:

> *L'évaluation de cet indicateur de performance sera confiée à une tierce partie externe. 1 Celle-ci sera chargée de compléter une grille d'évaluation, d'en faire une analyse et de rédiger un rapport. Les parties intéressées recevront cette évaluation initiale, la compléteront et proposeront des orientations relatives au renouvellement de l'indicateur de performance. Les paramètres de la grille d'évaluation seront précisés par l'expert dans le cadre de l'exercice de son mandat. La tierce partie retenue pour l'évaluation future de l'indicateur de performance sera mandatée par la Régie.*

We suggest that the Régie appoint an external expert to assist Gaz Métro in the development of a new Performance Indicator proposal. This proposal would then be presented to the Régie for review and approval.

4.2.4. Use Best Practices and Lessons Learned in Other Jurisdictions

This report has relied extensively on the highly relevant work of Costello and Wilson, who conducted an extensive and thorough survey of GPIMs in the US. However, with more time and resources, Gaz Métro can further review the most current best practices and lessons learned in other jurisdictions and apply them to a new proposal for a Performance Indicator. We reiterate two key best practices identified in the NRRI GPIM article, which Gaz Métro should integrate in any new proposal for a Performance Indicator: (a) set sharing rules to provide strong, symmetric incentives under all conditions; and (b) define the benchmark to approximate a reasonable strategy – not too easy to beat.

APPENDIX 1

A Hard Look at Incentive Mechanisms for Natural Gas Procurement

The National Regulatory Research Institute

November 2006

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Executive Summary

The gas procurement choices local natural gas distribution companies (LDCs) make, how they manage assets that are held for this function, and the extent to which costs are hedged far in advance determine the cost of gas their customers ultimately pay. Under the historical arrangements, utilities fully recover these costs from customers, subject to prudence review, under a purchased gas adjustment (PGA) tariff clause. Consequently, utilities have had no direct incentive to purchase, supply and manage the associated assets most economically.

Recognizing that stronger incentives for the gas procure¬ment function could lead to improved utility performance while reducing the need for detailed prudence reviews, state regulators in at least fifteen states have approved gas procurement incentive mechanisms (GPIMs) for one or more jurisdictional utilities. This paper discusses the economics of these incentive mechanisms and desirable features, presenting principles that should guide their design and some of the trade-offs that must be addressed. It describes pitfalls that result from certain design attributes in addition to discussing the regulatory review process for GPIMs.

This paper finds that existing GPIMs take a wide variety of forms across the country, differing in the scope of incentives, the approach to forming a benchmark, and the quality of the resulting incentives, among other characteristics. While some GPIMs are well-structured, design characteristics that result in weak or distorted incentives for some gas procurement decisions are quite common, with many GPIMs affording opportunities for the utility to increase its incentive award while not reducing, or even increasing, the customers' gas cost.

Contents

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06-15

Executive Summary

Local natural gas distribution companies (LDCs, utilities) have historically purchased and distributed natural gas to their customers within their service territories, passing through all associated costs. Beginning in the 1990s, various states implemented incentive mechanisms for the natural gas utility's supply procurement function. These mechanisms can potentially benefit consumers by eliciting better procurement performance leading to lower gas cost, while obviating the need for detailed and costly reasonableness reviews.

In most instances, utilities operating under gas procurement incentive mechanisms (GPIMs) have received incentive awards on a regular basis. However, GPIMs have also at times led to problems and disputes; many have been repeatedly modified, and some have been terminated. This paper discusses the economics of GPIMs, commenting on many of the characteristics of existing GPIMs. To a limited extent, it also reviews arrangements under which a utility contracts with a third party to perform the procurement function.

We have found that existing GPIMs take a wide variety of forms across the country, differing in the scope of incentives, the approach to forming a benchmark, and the quality of the resulting incentives, among other characteristics. While some GPIMs are well-structured, design characteristics that result in weak or distorted incentives for some gas procurement decisions are quite common, and many GPIMs afford opportunities for the utility to increase its incentive award while not reducing, or even increasing, the customers' gas cost. This paper also describes in detail some of the most common pitfalls in GPIM design.

Incentive mechanisms providing strong incentives properly aligned with customers' interests can reduce the need for detailed regulatory review of the procurement function, as a well-structured incentive mechanism's awards and penalties impose appropriate consequences for superior or inferior performance. However, to the extent a GPIM provides weak or no incentive for some aspects of procurement decision-making, a traditional review of these aspects remains appropriate. Moreover, to the extent an incentive mechanism provides distorted incentives and gaming opportunities, a more detailed and focused review would be needed to determine whether any abuse had occurred.

Our review of existing GPIMs indicates that very few are sufficiently broad and well-structured to eliminate the need for regulatory review of procurement decision-making. Yet in most instances, the regulatory reviews of GPIM results and of procurement decisions amount to little more than an audit of the utility's actual costs and incentive award calculations. The limited scope of the reviews in some cases suggests that the regulatory staff responsible for the reviews may not be aware of the incentive mechanism's shortcomings and the resulting weak incentives and gaming opportunities.

Finally, we also observe that the common measure of GPIM "savings" and customer benefits, based on the difference between a utility's actual gas costs and a GPIM benchmark, often provides an inaccurate (and overly positive) measure of utility performance and the impact of the GPIM. For many GPIMs, the benchmark is a simplified formula that is easy to beat without superior performance, and in some instances, the utility can raise the benchmark through its actions, creating a distorted measure of savings and benefits.

Well-structured GPIMs can provide real benefits to consumers; however, it may be difficult to achieve a sound design under some utility circumstances. The goal of this paper is to review and assess existing approaches to the design of these mechanisms, calling attention to some of the shortcomings in current designs and regulatory review processes, and recommend design approaches that can contribute to realizing the potential benefits of this innovative regulatory approach.

Introduction – The Rationale for Gas Procurement Incentive Mechanisms

Local gas distribution companies (LDCs, utilities) have historically performed a gas procurement function, purchasing natural gas for distribution to customers within their service territories. While most large customers and many smaller customers now purchase from a competing retail supplier or arrange their own purchases (with the LDC providing distribution service), most LDCs continue to be responsible for gas supply for many smaller residential and commercial consumers.

The gas procurement choices LDCs make, how they manage assets that are held for this function, and the extent to which costs are hedged far in advance determine the cost of gas their customers ultimately pay. Under the historical arrangements, these costs are fully recovered from customers, subject to prudence review, under a purchased gas adjustment (PGA) tariff clause. Consequently, utilities have had no direct incentive to purchase, supply and manage the associated assets most economically. Furthermore, the threat of a prudence review and possible disallowance can discourage utilities from actions (such as taking reasonable risks, or hedging) that might be in the customers' long-term interest, but can lead to higher gas costs under some circumstances.

With the unbundling and increasing competitiveness of the natural gas industry during the past two decades, LDCs have faced a much broader array of choices for acquiring gas supply for customers. This has made gas procurement more complex, with increased responsibility and risk for utility procurement managers. It has also made effective regulatory oversight more challenging and costly.

Recognizing that stronger incentives for the gas procurement function could lead to improved utility performance while reducing the need for detailed prudence reviews, state regulators in at least fifteen states have approved gas procurement incentive mechanisms (GPIMs) for one or more jurisdictional utilities (while many more states have implemented incentives applying to a more limited set of procurement-related actions). The characteristics of fifteen current GPIMs are summarized in Appendix 1, and Appendix 3 provides links to documents defining a few dozen GPIMs that are currently in force.

Regulators in some states have also approved arrangements under which the utility outsources all or part of its procurement responsibilities to a third party procurement agent and/or asset manager, generally a natural gas marketing company, and often an affiliate of the utility. These arrangements may involve incentive mechanisms or have similar properties to incentive mechanisms, and this paper also gives some attention to such arrangements. A few such arrangements are described in Appendix 2. Another alternative to traditional regulation of the utility procurement role is full retail supply competition, with the utility either excluded or serving in a highly restricted, "provider of last resort" role; this paper does not discuss this approach, as the focus here is on incentives applied to a utility procurement role.

Gas cost to consumers should decline as a result of a gas procurement incentive mechanism if the incentives lead to a reduction in the actual cost of purchased gas (compared with what it would have been without the incentives) that exceeds the incentive payment earned under the mechanism. With stronger incentives, LDCs and/or their procurement agents could lower gas cost by:

- Applying more resources to the function (employing more highly qualified staff, acquiring superior market intelligence, and so forth.);
- Taking greater advantage of the considerable buying power that LDCs and their agents have in the marketplace by virtue of the large, stable, firm loads they represent, to negotiate lower prices or better terms;
- Managing the substantial flexibility within asset portfolios to maximum advantage;
- Harvesting the full value of the transportation and storage assets held for the procurement function when they are not needed to meet customers' needs, generating revenues that offset gas costs; and
- Taking calculated risks that, lacking incentives, LDCs might be unwilling to take.

Regulated utilities are understandably concerned that if they take reasonable risks that are likely to benefit consumers, they will not share in the benefits but may well be penalized if adverse outcomes occur. With the utility sharing in the outcomes, good or bad, through an incentive mechanism, it may be more willing to take such risks, and regulatory authorities may feel less need to second-guess the decisions. As an example, a utility might reduce storage injections during a summer heat wave, to accommodate the temporarily high gas demands for electric generation and avoid high-cost purchases. However, this could risk missing storage targets and/or ultimately incurring higher costs for gas for storage, if prices later rise. If the utility is concerned that its purchasing for storage could be criticized, it will have little incentive to adjust the schedule in response to market conditions if the benefits all flow to customers. With an incentive mechanism, the utility can have a clearer incentive to balance the (uncertain) cost and benefits of such choices, and take reasonable risks.

The observation that most utilities across the country operating under GPIMs have regularly beat their benchmarks and earned incentive awards suggests that these incentive mechanisms have been successful and achieved their objectives. However, GPIMs have frequently been questioned and criticized by consumer advocates, regulatory commission staff, and utility customers. Several state public utility commissions have undertaken evaluations, reviews and/or surveys of gas procurement incentive mechanisms, either in the context of a specific company's results, or in a more generic regulatory proceeding.[1] Doubts have often been raised as to whether GPIM awards reflect superior performance and were deserved, and whether a GPIM benefits consumers. Such challenges have often led to reduced awards and changes to the GPIM structure. In several instances more serious disputes or allegations of utility misconduct have occurred around GPIMs.[2] Some GPIMs have been terminated, either by the initiative of the regulatory commission or the utility itself.[3] Appendix 5 provides a brief summary of some of the specific issues and complaints that have been raised around various GPIMs in the past.

This paper discusses the economics of these incentive mechanisms and desirable features, presenting principles that should guide their design and some of the trade-offs that must be addressed. Pitfalls that result from certain design attributes are described. The regulatory review process for GPIMs is also discussed.

Basic Structure of Gas Procurement Incentive Mechanisms

GPIMs around the country vary substantially in terms of the scope of the incentives (that is, to which procurement-related costs and/or revenues the incentives apply) and the mechanism's structure (how the specific incentives and awards are calculated). However, despite the wide variety, GPIMs generally all have the following fundamental structure:

- A formula is used to determine a "benchmark" value for gas cost (or for those components of gas cost or related revenues to which the incentives will apply), based on various natural gas price indices and other assumptions. In some instances the definition of GPIM excludes the term "benchmark"; however, while it may not be explicit, all incentive mechanisms can be interpreted as having a benchmark.[4] Benchmarks are further discussed in a later section of this paper.
- The LDC's actual cost or revenue result is compared to the benchmark value, typically on an annual basis.

1 As examples of recent reviews of gas incentive mechanisms, see Missouri Public Service Commission, Gas Supply and PGA Survey Results, August 2, 2005; Public Utility Commission of Oregon, Natural Gas Procurement Study, June 2005; State Utility Forecasting Group, Purdue University, Natural Gas Purchase Incentive Regulation and Benchmarking, A White Paper Prepared for the Indiana Utility Regulatory Commission, July 2005. The Public Service Commission of Wisconsin is presently investigating the appropriateness of various coal and natural gas procurement practices, including the gas procurement incentive mechanisms in place in that state (Docket No. 5-UI-110).

2 See, for instance, "Madigan Calls For $160 Million Refund For Nicor Customers," press release dated Nov. 21, 2003, by Illinois Attorney General Lisa Madigan, alleging that Nicor Gas improperly sold low-cost gas reserves in order to profit under its gas procurement incentive mechanism. The incentive mechanism has been cancelled and the refunds are presently a subject of Illinois Commerce Commission Docket No. 01-0705.

3 As examples, GPIMs were once in place but have since been terminated for Nicor Gas (IL), Minnegasco (MN), Columbia Gas of Pennsylvania (PA), and Avista Utilities (WA). Laclede Gas (MO) had a GPIM that was terminated but later redesigned and reinstated.

4 As one example, Avista (OR) has a Purchased Gas Cost Adjustment provision that sets rates in advance based on estimated prices and purchase quantities, and then credits the PGA Balancing Account with 90% of the difference between the estimated costs used for billing and actual costs. The estimated costs serve as the benchmark, and the utility's incentive results from the 10% of the actual cost difference that does not flow through the PGA mechanism.

- A "sharing rule" assigns a portion of the difference between actual and benchmark values to the utility (typically considered an incentive "award" if actual cost is lower than the benchmark, or a "penalty" if actual cost exceeds the benchmark). The utility's award or penalty is typically 50%, 25% or 10% of the difference between actual and benchmark gas cost.

Table 1 illustrates the operation of a GPIM, with an incentive award in Year 1 and a penalty in Year 2. As the summaries of GPIM structures in Appendix 1 show, around this basic GPIM structure many variations exist.

Table 1: Illustrative Example of a Gas Procurement Incentive Mechanism

GPIM Year	Year 1	Year 2
Computed benchmark gas cost ($ millions)	$47.0	$49.0
Actual gas cost	45.4	49.8
Difference – amount actual gas cost is below the benchmark	1.6	-0.8
Utility incentive award (@ 25%; negative value is a penalty)	0.4	-0.2
Total cost to customers: actual gas cost plus utility award/penalty	45.8	49.6
"Savings" to customers (difference between total cost and benchmark)	1.2	-0.6

Note: This example assumes a sharing rule that assigns 25% of the difference between actual and benchmark gas costs to the utility as an award/penalty, and no tolerance band.

Source: Authors' Construct

Note that a GPIM provides an incentive for the decisions regarding a particular cost or revenue category only if it establishes a separate benchmark value for the category to which actual costs or revenues can be compared. No incentive is created for a particular cost or revenue category, and the associated decisions, under the following types of arrangements:

- No incentive is created for a particular cost or revenue if it is excluded from both the actual cost and benchmark cost calculations.

- No incentive is created for a particular cost or revenue if the actual cost or revenue value is included in the benchmark cost calculation. Under this arrangement, the particular cost or revenue category will pass through to customers and not contribute to any difference between actual and benchmark costs.

- No incentive is created for a particular type of decision if the utility's actual choices are reflected in the benchmark calculation. For instance, if the actual quantities purchased at each supply location are used in the benchmark calculation, the incentive mechanism does not create an incentive to optimize the purchase locations.

Under outsourcing arrangements, the counterparty supplier typically commits to provide gas supply and/or asset management under pricing defined in a contract, often taking control over the utility's firm transportation and storage assets. The pricing may be based on published indices, and the supplier may pay a fixed fee for the right to market excess transportation and storage capacity. In some instances the pricing formula is structurally similar to a GPIM benchmark and sharing rule, with a portion of the savings achieved by the supplier flowing back to the utility and its customers (see Appendix 2 for the description of one such agreement).

Under such arrangements, the counterparty marketer is usually expected to achieve lower gas cost by optimizing procurement through its larger portfolio, combining the utility's assets with other assets. The utility should be able to capture a portion of the expected benefits of such arrangements for consumers through the outsourcing agreement, whether it results from a bilateral negotiation or a competitive procurement. Because the regulated utility likely remains ultimately responsible for reliable gas supply, it typically remains closely involved in procurement decision-making, in frequent contact with its supplier.

Discussion of Key GPIM Design Characteristics

This section describes the key elements of GPIM design in greater detail, discussing the major benefits and drawbacks of various approaches, and noting the characteristics of many existing GPIMs. A later section of the paper provides a summary of recommended GPIM design approaches.

This section discusses the incentive properties that result from various design attributes. Many GPIMs have characteristics, such as tolerance bands or caps on utility awards, that, under some circumstances, can weaken or eliminate incentives. For the purpose of this discussion, it is generally assumed the utility anticipates that its incremental choices could potentially increase or decrease its award or penalty, and therefore faces active incentives.

1. *Objectives and Scope*

The objective of most GPIMs is to provide incentives for achievement of lower short-term procurement costs. Many GPIMs are designed to provide incentives for all or nearly all procurement-related costs, including supply (commodity), transportation, and storage, as well as for revenues from resale of unused transportation and storage capacity and off-system gas sales.[5] However, some utilities have incentives only for commodity purchases, while others have incentives confined to off-system sales and capacity releases.

In most instances, GPIMs do not attempt to provide direct financial incentives for decisions concerning longer-term firm pipeline and storage reservations, which have an impact on reliability and price stability in addition to short-term gas cost. Reliability and price stability are objectives different from, and in competition with, the objective of low gas cost, and it would be difficult or impossible to provide effective incentives for these conflicting objectives within a single incentive mechanism; we are not aware of a successful attempt to do so. The accompanying box describes how hedging can be accommodated or encouraged, without putting the utility at risk, when a utility operates under a GPIM. However, management of long-term firm assets in the short term (for instance, using excess resources to gain incremental revenues from gas sales or capacity releases to offset gas cost), is generally within the scope of a GPIM's incentives.

GPIMs that encompass as broad a scope of interdependent procurement-related costs and revenues as is feasible, within a single incentive calculation applicable to all costs, provide the best incentives. Incentive problems can arise when a GPIM creates unequal incentives for various types of procurement decisions; these potential problems are discussed in a later section of this paper.

With regard to contractual arrangements for procurement and asset management, such contracts will determine the division of responsibilities between the utility and the agent, and the scope of the incentives provided for low gas cost or other objectives. In some instances, the agent takes control of storage and firm transportation contracts and is responsible for all gas procurement; in other instances, the utility retains control over some day-to-day procurement decisions.

5 Examples of fairly comprehensive GPIMs are PG&E and SoCalGas (CA), LG&E (KY), Atmos and Nashville Gas (TN), Alliant and Superior (WI).

GPIMs and Hedging of Gas Costs

Many current GPIMs were designed in the mid-1990s when gas prices were relatively low and stable, and few regulatory commissions were encouraging utilities to hedge gas costs. So it is not surprising that many GPIM benchmarks assume only short-term gas purchases (with monthly and daily pricing), and little or no forward purchasing or hedging other than through storage. However, as natural gas prices have increased and become more volatile in recent years, interest has grown in providing customers with greater price stability, which can be achieved through physical forward purchases or financial hedging. But when a GPIM benchmark assumes only short-term purchases, it places the utility at risk through the GPIM for the costs and outcomes of any substantial amount of forward physical purchases or financial hedges. This discourages hedging.

To accommodate hedging, a GPIM can include a target schedule and quantity of hedging in the benchmark (an example of a GPIM benchmark that includes a schedule for hedging is New England Gas) or set benchmark prices based on forward prices (this approach is taken for the Oregon utilities). The utility could be permitted to hedge more or less, or sooner or later, than the benchmark schedule (perhaps limited to some range), but would be at risk if its adjustments to the schedule ultimately result in higher or lower gas cost. This would encourage hedging, as the utility would minimize its risk under the GPIM by staying close to the hedging schedule reflected in the benchmark. Another approach to accommodating hedging is to exclude both the costs and impacts of hedges from actual and benchmark cost calculations under the GPIM, so the utility's hedging program occurs entirely outside of the GPIM and has no impact on incentive awards.

2. *Design of the Benchmark*

The central element of GPIM design is the benchmark formula, which determines to what costs and revenues incentives apply, the strength and nature of incentives, the relative likelihood of award or penalty, and the utility's exposure to risk as a result of the GPIM.

As discussed above, the scope of some GPIMs encompasses nearly all procurement-related costs and revenues from management of assets held for procurement purposes, while under other GPIMs, incentives apply to a more limited set of costs and revenues. For brevity, the discussion that follows will often assume a GPIM that pertains to "gas costs"; however, in most instances the concepts are equally applicable to more narrowly-focused GPIMs or those applicable only to asset management revenues.

For some incentive mechanisms, there is no explicit benchmark. For instance, under some incentive mechanisms, the utility keeps all revenues from capacity release net of a fixed annual dollar amount. In this case, the fixed dollar amount can be considered the benchmark.

The overriding objective of a GPIM is to provide incentives for performance surpassing that which would be reasonable and expected under traditional regulation. Under a GPIM, there is no incentive award or penalty if actual costs equal (or are within a tolerance band around) the benchmark, and the utility receives an incentive award if it beats the benchmark. This suggests that, in principle, the benchmark should be designed to reflect the gas cost that would result from a reasonable procurement strategy reflecting acceptable, but not superior, performance deserving of no award or penalty.

For a GPIM applicable to gas cost, the simplest benchmark would be a fixed dollar figure set in advance, representing a forecast of gas cost. However, this simple approach would expose the utility to substantial risk due to factors that it cannot control, such as the weather-induced variability of gas loads or large movements in natural gas market prices. To remove these risks from the mechanism and focus incentives on factors under utility control, benchmark formulas typically take into account actual load levels and actual market prices as reflected in published indices.

Variability of weather-induced load levels, locational price differences, and other market characteristics lead to dynamic adaptations to procurement strategies that can be difficult to embody in a formula. Consequently, it can be complex to define a benchmark formula that will approximate the cost result of a reasonable procurement strategy under all likely future circumstances. In practice, benchmark formulas are generally kept simple, and, as a result, benchmarks typically reflect implied purchasing rules and strategies that are often easy to improve upon under actual conditions.

For example, under some GPIMs, the benchmark assumes purchases from available supply basins in fixed proportions, based on historical averages, a gas supply forecast, or firm pipeline reservation quantities.[6] If relative prices change and the utility has substantial flexibility to optimize purchase locations, the resulting benchmark may be easy to beat by a significant amount. Other GPIMs determine the mix of purchase locations to be assumed in the benchmark through a formula that adapts to relative prices to some extent.[7] However, designing a benchmark formula that reflects how procurement decisions should adapt to external conditions will tend to increase its complexity, which can render it more costly to audit and increases the potential for misunderstandings or disputes.

While it is important for a GPIM benchmark to reflect external conditions, such as load and prices, which are outside of utility control, it is also important that a GPIM benchmark not use parameters that are under utility control. It is a fundamental principle of the design of incentive mechanisms that a benchmark should provide an external and independent basis for evaluating company performance. This means that the benchmark calculation should use only parameters and assumptions that are independent of the utility's actual purchasing decisions (we call this an exogenous benchmark). If the benchmark is exogenous, the utility can only increase its award by lowering actual gas cost, not by raising the benchmark; as a result, utility and customer interests are aligned.

Any assumptions in the benchmark calculation affected by utility choices result in a benchmark that is not exogenous; as a result, some incentives are weakened, eliminated, and/or distorted. Such a GPIM may sometimes reward actions that are not in the customers' interest, or fail to reward actions that are in the customers' interest. Unfortunately, our review has found that an exogenous benchmark is the exception rather than the rule – most of the GPIMs summarized in Appendix 1 do not have a fully exogenous benchmark, with the most common compromise being the use of actual purchase quantities in the benchmark. Discussion of non-exogenous benchmarks and other common GPIM pitfalls is provided in a later section of this paper. Appendix 4 provides an arithmetic derivation of the incentive properties resulting from GPIM structure, demonstrating some of the principles described in this section, including the importance of an exogenous benchmark.

3. *Sharing Rules*

The actual utility award or penalty under a GPIM is determined in a periodic GPIM accounting review, in which actual costs are tallied, the benchmark is computed, and the difference between actual and benchmark costs is calculated and assigned to customers and to the utility according to the GPIM's "sharing rules." The following are common elements of a GPIM's sharing rules:

<u>GPIM accounting period</u> – Application of the GPIM sharing rules is usually performed on annual results, with some GPIMs calculating awards/penalties based on monthly or biannual results. The advantage of an annual period is that it encompasses a complete storage cycle and all seasons. Since some gas purchased in summer is consumed in winter, it would seem to make sense to pass judgment on a procurement strategy only once the annual cycle has been completed. Calculating awards and penalties on a shorter-term basis could lead to gaming opportunities if the utility is able to shift costs or revenues between periods in order to maximize an award.

<u>Sharing percentages</u> – The sharing percentage attempts to balance multiple objectives under each utility's particular circumstances. Assigning a larger percentage to the utility provides a stronger incentive, and the potential awards should be large enough to induce an appropriate level of effort to perform the procurement role effectively and reduce gas cost. A

6 Examples are Laclede Gas (MO), whose benchmark uses fixed percentages by location; Avista (OR), whose benchmark uses the weather-normalized prior year actual quantities; Alliant/Wisc. P&L (WI), whose benchmark uses pipeline reservation quantities; and Superior WP&L (WI), whose benchmark uses volumes from its Gas Supply Plan.

7 An example of a benchmark that determines assumed purchase quantities by location in a manner that adapts, to some extent, to changes in relative prices is PG&E (CA).

larger percentage assigned to the company also imposes more risk, and could lead to more risk-averse, cautious actions; the utility might tend to forego attractive but somewhat risky opportunities, raising gas costs. A larger percentage assigned to the utility also directs more of the benefit from beating the benchmark to the company and less to customers. This will be more of a concern if the GPIM's benchmark is too easy to beat, or if external events can cause very large differences between benchmark and actual costs.

Some GPIMs[8] provide for asymmetric awards and penalties, for instance, with a smaller utility share of savings against the benchmark and a larger utility share of costs in excess of the benchmark. The intent may be to make the GPIM more advantageous for customers overall by assigning them a larger share of savings and a lower share of excess costs. However, this approach distorts incentives somewhat, since a different percentage applies to gains as to losses. A better approach to rebalancing a GPIM with regard to anticipated utility and customer outcomes would be to shift the benchmark (for instance, by adding/subtracting a fixed dollar amount) or, equivalently, to use an off-centered tolerance band (one that requires a larger difference between actual and benchmark costs to earn an award).

Some GPIMs[9] assign a lower percentage to the utility for larger differences between actual and benchmark gas costs, while others[10] set a cap (maximum level) for awards or penalties. This approach reduces the utility's risk and also the chance of a very large award. This approach could also be appropriate if it is felt that the larger the difference between benchmark and actual cost, the more likely it is that uncertain external events outside of utility control are at play, and large awards or penalties may be relatively undeserved. These approaches are generally undesirable, as any time a utility anticipates that a low sharing percentage will apply or its outcome will be capped, the GPIM's incentives are weakened or eliminated.

Other GPIMs[11] assign a larger percentage to the utility for larger deviations between the benchmark and actual costs. The logic could be that larger savings are more difficult to achieve and require larger incentives. This approach also distorts incentives, and can encourage risk-taking that is not in the customers' interest.

Tolerance bands – Some GPIMs have tolerance bands; if the difference between benchmark and actual cost is small, there is no award or penalty. The purpose can be to eliminate the need for determination of a specific award or penalty under some circumstances, or to afford the utility some flexibility in its procurement decision-making without risk of incurring a penalty. A larger tolerance band weakens incentives: to the extent the utility may at times anticipate that its GPIM outcome is likely to end up within the tolerance band, incentives are weaker. Off-centered tolerance bands are also common,[12] and they essentially shift the benchmark, making it easier or harder to beat and adjusting the relative benefits to the utility and customers. Tolerance bands, if used at all, should be narrow to avoid blunting incentives.

Some Common Pitfalls in GPIM Design and Structure

Our review has found that existing GPIMs generally do not achieve all of the design objectives suggested in the discussion in the previous section to the fullest extent, and, consequently, they provide weak or distorted incentives for some types of procurement actions; or they expose the utility and customers to some risk of awards or penalties that may at times be excessive and undeserved.

Of course, utilities will not necessarily act according to the incentives of their GPIM, especially when there is a known conflict with customers' interests. This does not mean such conflicted incentives are benign. To the extent such conflicts exist, the incentives serve no useful purpose while increasing the risk of actions contrary to customers' interests and the potential need for more detailed review of purchasing decisions.

8 Examples of GPIMs with asymmetric percentages are PG&E (CA) and SoCalGas (CA), which assign 25% for awards, capped, and 50% for penalties, uncapped; and Laclede Gas, which provides for awards but no penalties.

9 GPIMs with lower percentages for larger deviations from the benchmark include SoCalGas (CA), Laclede Gas (MO), Louisville G&E (KY).

10 GPIMs that cap awards and/or penalties include PG&E and SoCalGas (CA), Superior WP&L (WI), New England Gas (RI), MidAmerican (IA).

11 Examples are Nashville Gas (TN), Indiana Gas (IN), and Louisville G&E (KY).

12 Examples of GPIMs with off-centered tolerance bands are PG&E and SoCalGas (CA), Superior WP&L (WI), Atmos (TN), MidAmerican (IA).

This section describes some of the most common characteristics found in GPIM designs that compromise the incentives provided, create gaming opportunities, and/or lead to larger company awards even if performance is not better than would be expected without incentives.

1. ***Different incentives (sharing percentages) applying to inter-related procurement actions***

One common GPIM design characteristic that can lead to incentive problems is the application of GPIM incentives only to certain cost components, or very different sharing percentages applying to different cost or revenue categories.[13] This encourages the utility to increase its GPIM award by exercising any flexibility it may have to spend relatively more in areas where incentives do not apply or are weaker, to reduce other costs (or increase revenues) to which stronger incentives apply. This can be contrary to the customers' interests.

For example, some GPIMs assign to the utility a larger percentage of capacity release revenues than of commodity costs savings.[14] When capacity is released, the utility may incur additional cost for short-term transportation or downstream purchases, and it also may lose opportunities for profitable off-system gas sales. The potential revenue from some capacity releases may not justify the incremental supply and transportation cost, but this choice would be distorted by a GPIM that offers the utility a higher percentage of the capacity release revenue than of commodity cost savings.

Some GPIMs pass all capacity release revenues through to customers, while applying incentives to commodity costs. This structure also distorts incentives and creates a conflict between utility and customer interests under some circumstances.

2. ***Benchmarks that are too easy to beat***

A common GPIM characteristic is a benchmark that is easy to beat, so the utility need not achieve superior performance to earn an award. The benchmark might be highly simplified or inflexible in some respects and, as a result, represents a level of cost and implied procurement strategy that under many circumstances, if subjected to a reasonableness review, would likely be found imprudent. For instance, the benchmark might not reflect optimization of purchase locations, or it might include low expectations (or no expectations) with respect to revenues from release of unneeded capacity, or it might assume the utility must pay full transportation tariffs when discounting is common, to note a few examples.

Note that even if the utility achieves superior performance relative to what would have been expected under traditional regulation, if a benchmark is too easy to beat, consumers can be harmed and end up paying more. Table 2 provides an illustrative example of this.

13 Examples of GPIMs that apply very different incentives to different cost or revenue categories are NIPSCO (IN), Indiana Gas (IN), New Jersey Natural Gas (NJ), NYSEG (NY), New England Gas (RI), Atmos (TN), Nashville Gas (TN). See Appendix 1 for details.

14 Examples are New Jersey Natural Gas (NJ) and New England Gas (RI).

Table 2: Illustrative Example of Harm to Consumers If Benchmark Is Too High

Gas cost under traditional regulation without incentives (hypothetical) ($ mil.)	$47.0
Actual gas cost achieved under incentive mechanism	46.0
True cost savings, relative to traditional regulation, under incentive mechanism	1.0
Calculated benchmark cost under incentive mechanism	49.0
Calculated "savings" relative to (flawed) benchmark	3.0
Utility incentive award (@ 50%)	1.5
Total cost to customers: actual gas cost plus utility incentive award	47.5
Customers' actual "savings" relative to total cost under traditional regulation	-0.5

Source: Authors' Construct

In some instances, it may have been recognized at the time the GPIM was established and its benchmark defined that it would be easy to beat, and this was part of the deal; perhaps the GPIM incorporates an expected level of utility earnings that, if not provided in this manner, would have to be provided in some other manner.[15] While this may be a reasonable arrangement, it must be recognized that under these circumstances, the benchmark does not reflect the results of a reasonable procurement strategy, or the costs that would be achieved in the absence of the incentive mechanism. Under such an arrangement, the difference between the benchmark and actual costs, and the portion of this difference assigned to consumers, cannot be called "savings." If a GPIM is designed to provide an expected level of utility earnings, this should be explicit, and this objective should be recognized when the GPIM results are evaluated and reported.

3. *Use of actual purchase volumes (by time, location, or type of deal) in the benchmark*

Another common design compromise is the use of actual utility purchase volumes by month, location, and/or type of purchase in the benchmark calculation.[16] The motivation for doing this is clear—it is a simple approach to creating a benchmark that adapts to a broad range of external circumstances, such as changing relative prices and overall load levels, and keeps the benchmark close to actual costs.

While a GPIM benchmark should adjust to changing load levels, which are not under utility control, some incentives are eliminated, and others may be distorted if the benchmark reflects actual utility purchasing decisions. When a GPIM benchmark uses details of actual utility purchase or net purchase volumes (or weights reflecting them), it means that the utility's choices and actions affect the benchmark. The benchmark is no longer exogenous, and incentives can be distorted to a surprising extent, as further elaborated in the next several subsections.

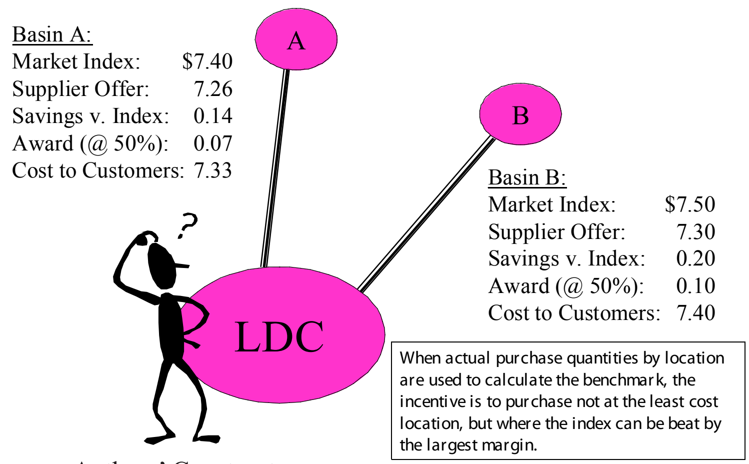
As a simple example, consider a utility that can purchase supply from either of two basins, A or B. Figure 1 illustrates that when actual purchases by location are used in the benchmark, each purchase is essentially benchmarked to a price index at the location of the purchase. As a result, the GPIM incentive is not to purchase the least cost supply, but to make the deal that allows beating the respective locational price index by the largest amount, earning the utility the largest incremental award.

In the example in Figure 1, the supplier at Basin A is offering the lower cost supply, but the potential award is larger for purchases at Basin B due to a higher index, resulting in a conflict between the utility's interests under the GPIM and the interests of its customers.

15 As one example, Laclede Gas (MO) has argued that without the earnings from its incentive mechanism, it cannot earn its authorized return.

16 Examples of GPIMs that use actual purchase volumes by time, location, and/or type in the benchmark calculation are SoCalGas (CA), Southwest Gas (CA), MidAmerican (IA), NIPSCO (IN), Indiana Gas (IN), Louisville G&E (KY), New England Gas (RI), Atmos (TN), Chattanooga Gas (TN), Nashville Gas (TN).

Figure 1: An Incentive Problem Resulting From Use Of Actual Utility Purchase Quantities To Calculate the Benchmark



Source: Authors' Construct

By contrast, if the volumes used in the benchmark are independent of utility choices (for instance, set by a rule that is a function only of actual loads and market prices, which the utility does not control), the utility always has the proper incentive to attempt to purchase the lower cost supply.

The situation described in Figure 1 may be rare in some areas, and under many circumstances utilities may not be able to anticipate price indices or the gap between offers and indices. While the use of actual purchase locations in the benchmark, under a utility's particular circumstances, may only rarely give it a strong incentive to purchase in a manner contrary to its customers' interests, this approach to calculating a benchmark always fails to provide the proper incentive to purchase at the lowest cost location, except by coincidence. Under an exogenous benchmark, the utility has an incentive to accept the offer from Basin A in the example in Figure 1, as it is $0.04 cheaper and the utility would anticipate sharing in this benefit. Under a benchmark that uses actual purchase locations, it may be unclear which purchase location is more advantageous to the utility under many circumstances, but under such a mechanism it does not have a clear incentive to purchase at the least cost location.

In sum, the use of actual purchases by location, time, or type in the benchmark has the direct effect of eliminating any incentive for the utility to optimize purchases by location, time or type. Moreover, as the following paragraphs describe, use of actual purchases in the benchmark creates additional serious incentive problems in the presence of certain other benchmark features.

4. *Use of assumed transportation charges and actual purchase quantities by location in the benchmark*

Use of actual purchase locations in the benchmark can lead to serious incentive problems around choices between purchases at upstream and downstream locations, or other locations between which transportation charges may differ. For instance, suppose Basin C and Basin D are usually highly competitive into the LDC, with both basins offering the same delivered cost because of the discounting of transportation. It would then be the case that the utility would often have little to gain in choosing among purchases at Basin C, Basin D or its citygate market. However, for some GPIMs, if price indices are not available at all three points, the benchmark calculation assumes payment of the full tariff transportation rate between the basins and the citygate.[17] This could lead to an exaggerated benchmark for basin purchases (basin index plus transportation charge), or an understated benchmark for citygate purchases, essentially rewarding the utility for achieving transportation costs below the tariff rate. The utility will have an incentive to purchase from the basin with the higher nominal transportation rate, as this will lead to a higher benchmark and higher awards. While the actual purchased gas cost may be unaffected (as, by assumption, delivered costs are similar for all three locations), due to the higher GPIM awards, consumers may ul-

17 Examples of GPIMs that have this characteristic are MidAmerican (IA) and Louisville G&E (KY),

timately pay more, as in the illustrative example in Table 2. The problem is eliminated with an exogenous benchmark that does not reflect the utility's actual purchases by location. This problem (use of actual purchase locations in the benchmark, with assumed transportation charges) can also distort incentives with regard to capacity release choices.

5. ***Use of actual net purchase quantities (reflecting actual storage injection quantities) in the benchmark***

A similar incentive problem results if the utility's actual storage injection volumes are reflected in the benchmark (this would be the case if net purchases, net of storage, were used in the benchmark).[18] As an illustration, suppose a utility chooses to delay storage injections during spring and early summer, planning to catch up later in the summer. An exogenous benchmark would include a specific storage injection schedule, or one based on parameters independent of the utility's actual choices, placing the utility at risk for a share of the cost impact of deviations from the benchmark schedule. With a benchmark that uses actual monthly purchases (reflecting actual storage injections and withdrawals), the utility would not be at risk for whether its chosen injection timing turned out well or poorly, as the benchmark would reflect the choice. As with purchase locations, the incentive would be to purchase not when supply is cheaper, but when the indices could most likely be beat.

The use of actual net purchase quantities in the benchmark, resulting in weak incentives applying to the timing of storage injections, can be costly for customers. An extreme example is SoCalGas' storage fills during the 2000-2001 period. In 2000, SoCalGas injected relatively little gas for its customers during the spring and early summer, when prices into the SoCalGas system (SoCal Topock) were in the \$2 to \$4 range, and had to catch up during July to October when prices rose to the \$4 to \$6 range. In 2001, SoCalGas' injection had the opposite pattern, with a relatively large amount injected before July 1 and very little after July 1; but prices were above \$10 until June-July, after which they fell back under \$4. The SoCalGas incentive mechanism reflects the actual pattern of storage injections in the benchmark, so the cost impact of the actual injection pattern relative to, for instance, a ratable injection pattern is not reflected in the calculations of ratepayer benefits or utility award. In its review of SoCalGas' incentive mechanism during this period, the Office of Ratepayer Advocates compared actual and benchmark gas costs, and concluded that SoCalGas did an effective job of managing gas procurement, saving ratepayers \$192.7 million and \$172.4 million in 2000-2001 and 2001-2002, respectively.[19] More recently, following criticisms of the timing of SoCalGas's storage injections for the 2004-2005 period, additional restrictions on the timing of storage injections have been imposed.[20]

The direct impact of reflecting actual utility injection timing in the benchmark is only to eliminate any incentives with respect to the timing of injections; however, it may contribute to more problematic incentive problems. For instance, if the utility shares in revenues from release of unused storage, or in hub services that can be provided from utility storage, it will have an incentive to time its injections in order to maximize the opportunities to earn these revenues, and this may be contrary to the interests of consumers.[21]

6. ***Use of actual net purchase quantities reflecting daily market transactions, with first-of-month prices used in the benchmark***

A serious incentive problem arises if a GPIM uses first-of-month prices in the benchmark along with net actual purchase quantities reflecting incremental gas purchases or sales on the daily market during the month.[22] Under this arrangement, in effect, the first-of-month price is the benchmark price for any incremental purchases or sales on the daily market during

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18 GPIMs that appear to use actual purchase quantities net of storage include SoCalGas (CA), MidAmerican (IA), LG&E (KY), and Laclede Gas (MO).

19 SoCalGas received large incentive awards for these years that are subject to modification as a result of an ongoing investigation in CPUC Docket No. I.02-11-040.

20 The ratepayer advocate criticized SocalGas' storage injections in its annual monitoring report and initially recommended that SoCalGas be required to inject gas ratably. Office of Ratepayer Advocates, Monitoring and Evaluation Report of Southern California Gas Company's Gas Cost Incentive Mechanism, April 1, 2004 through March 31, 2005 (GCIM Year 11), November 30, 2005, p. 1-4.

21 Under the SoCalGas (CA) incentive mechanism, SoCalGas earns substantial revenues from hub services that flow through its incentive mechanism, with no associated benchmark value, contributing a large component to annual incentive awards.

22 The SoCalGas (CA) and Laclede Gas (MO) incentive mechanisms appear to have this characteristic.

the month. As a result, if prices on the daily market rise above the first-of-month price, incremental off-system sales on the daily market provide an additional GPIM award, regardless of whether they are likely to ultimately lower total gas cost and benefit customers. Similarly, if prices on the daily market fall below the first-of-month price for the month, incremental purchases on the daily market provide an additional GPIM award, again regardless of whether they are likely to ultimately benefit consumers.

Such incremental purchases or sales increase the GPIM award because they increase the difference between the benchmark and actual costs in the current month (contributing to a larger GPIM award), and the transactions can generally be offset in a future month through incremental or decremental purchases at benchmark prices with no GPIM impact. While such transactions are sure to expand the GPIM award (assuming a tolerance band or award cap does not apply), their ultimate impact on the cost to consumers depends upon the future prices at which the transactions can be offset, and the GPIM sharing percentage. However, to the extent the current spot price is a good predictor of next month prices (which, due to arbitrage using storage, it generally is), these transactions increase GPIM awards at the consumers' expense. Table 3 provides an example of how use of first-of-month prices and actual net purchase quantities in the benchmark can cause distorted incentives to engage in daily market transactions.

Table 3: Example of the Perverse Incentive for Incremental Gas Sales or Purchases on the Daily Market When the Benchmark Uses FOM Prices and Actual Net Purchases

	If the spot price rises above the FOM price, incremental sales are attractive:	If the spot price falls below the FOM price, incremental purchases are attractive:
The utility can increase its GPIM reward through incremental transactions if spot prices rise above OR fall below the FOM price:		
First-of-month price index for May	$6.00	$6.00
Spot price when incremental gas sale (purchase) is contemplated	$7.00	$5.00
Impact of the sale (purchase) on actual cost for May (per MMBtu)	-$7.00	+$5.00
Impact on the benchmark for May (@ May FOM price)	-$6.00	+$6.00
Total impact of gas sale (purchase) on the difference between benchmark and actual cost (positive values lead to award)	+$1.00	+$1.00
Total impact on utility award (assuming GPIM sharing rule assigns 50% of the difference to the utility)	+$0.50	+$0.50
The utility can offset the incremental transactions the next month at benchmark prices, with no impact on its GPIM award:		
Impact of repurchase at June FOM price on actual cost for June	+$7.00	-$5.00
Impact of the June repurchase on benchmark for June	+$7.00	-$5.00
Total impact on difference between benchmark and actual costs	$0.00	$0.00
The ultimate impact on the cost to customers will depend on the cost of the future gas purchase that is needed to replace the gas sold at this time (or, if an incremental purchase was made, the cost of the future purchase that is not needed due to the incremental purchase at this time). Assuming the spot price is an accurate predictor of next month's FOM price:		
Total impact on actual cost (May + June)	$0.00	-$0.00
Total impact on utility award (May + June)	+$0.50	+$0.50
Total impact on total cost borne by customers, including change in actual cost plus change in award	+$0.50	+$0.50
Source Authors' Construct		

This problem arises because the GPIM, in effect, benchmarks incremental spot purchases or sales on the daily market to an index that, at the time of the decisions, no longer accurately reflects the value of the incremental or decremental supply. When contemplating any procurement choice, such as an incremental purchase or off-system sale, the utility should focus on whether it would ultimately contribute to lower overall costs for customers. The choice is often between a purchase (or sale) at the present time, and a purchase (or reduction in purchases) at some later time. Incremental purchases on the daily market late in a month are advantageous to consumers if they reduce the need for future purchases that may ultimately be higher priced. Thus, the right perspective is a going forward view of likely market prices. GPIMs that, in effect, benchmark certain decisions to prices, indices or averages that, at the time of the decision, reflect past market conditions, introduce distorted incentives and opportunities to increase GPIM awards at the customers' expense.

An exogenous benchmark avoids this problem, even if it uses first-of-month prices exclusively. This is because the benchmark quantity for each month is independent of the utility's actual purchases. An incremental purchase or sale at any time will increase the utility award only if it contributes to lower gas cost over the course of the entire GPIM period.

7. *Use of actual purchase quantities in the benchmark, with non-standard contract provisions*

Use of actual purchase volumes in the benchmark also distorts incentives with respect to additional contract provisions that change the value and price of a purchase relative to the standard monthly contracts that the price indices used in the benchmark primarily reflect.

A utility buyer may receive a discounted price on a monthly purchase by offering the seller valuable flexibility, such as rights to recall the supply or to terminate the contract at any time during the month. If actual purchases are used in the benchmark, the utility may be able to increase its award with such deals, as they would be benchmarked to the price indices that primarily reflect standard transactions calling for a firm, constant daily quantity throughout the month. However, such recall rights could lead to costly replacement purchases when the supply is recalled under tight market conditions.

With an exogenous benchmark, the utility would have an incentive to provide such recall rights only if the expected value of the additional cost incurred for replacement supply was less than the discounts received and, therefore, offering the discounts would be expected to lower total gas costs. The utility's incentive would be aligned with the customers' interests.

However, if actual purchase quantities are used in the benchmark, the utility may anticipate that any replacement purchases could be arranged so that they are priced at benchmark. For instance, this could be achieved by initially relying on storage, to defer the replacement purchases to a later month when the utility can purchase the gas at the benchmark index. If this is the case, the utility will have an incentive to enter into such contracts to increase its GPIM award, even if total customer gas cost is raised as a result.[23]

Similarly, such an arrangement would penalize the utility for any contracts that offer added value (such as additional buyer flexibility or reliability) for a premium. Some GPIMs attempt to address this problem by allowing the addition of certain premiums to the benchmark (i.e., to be flowed through to customers).

8. *Inappropriate cost basis for off-system sales*

Many GPIMs do not clearly specify how the cost basis is established for off-system sales. In some cases, a sale from storage may be priced at the average cost of gas in storage. In many cases, the utility may have some flexibility in assigning cost to the sale so as to maximize its incentive awards. How costs can be assigned to off-system sales may also distort decisions as to whether to make off-system sales or to inject additional gas into storage on any day. A GPIM encompassing all procurement costs and offsetting revenues, with an exogenous benchmark, avoids such incentive problems.

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23 As an example, NIPSCO's incentive mechanism explicitly states that contracts with such supplier recall rights are benchmarked to first-of-month prices, with "any replacement gas" also benchmarked to first-of-month prices. However, virtual storage deals, and parks and loans, are not benchmarked, and these or other approaches potentially could be used to replace any recalled gas with little or no impact on the incentive award.

9. ***Sharing rules providing asymmetric awards and penalties***

As noted earlier, some GPIMs provide awards but not penalties. Such an asymmetry provides a distorted incentive for risk-taking. For instance, the utility would share in the benefits of hedges that are in the money, but would not share in their costs if out of the money. At the same time, this arrangement makes hedges a bad deal for consumers, as they would bear all of the downside while sharing the upside.

Other GPIMs provide substantially different sharing percentages for awards than for penalties. Similarly, this distorts the incentives with regard to actions, such as forward purchases or financial hedges, that could lead to gains or losses relative to the benchmark.

10. ***Potential for gaming between consecutive GPIM accounting cycles***

Most GPIMs operate on an annual cycle (calculating the benchmark and actual costs, and applying sharing rules, to combined results over 12 months), while other GPIMs use a monthly or biannual cycle. Whatever the cycle, a GPIM can create opportunities and incentives for a utility to shift costs or revenues from one cycle to the next to maximize awards. For instance, if, near the end of a cycle, the utility anticipates that it cannot improve its award in the current cycle (perhaps due to hitting a cap, or results falling into a tolerance band), it would face an incentive to shift costs into, and revenues out of, the current cycle, to maximize its award in the next cycle. A utility might have some flexibility at the end of each cycle with respect to storage inventory levels, and hedging may also present an opportunity to incur costs in one period with the benefits to be realized in a later cycle. These particular problems can be addressed by adjusting for inventory discrepancies at the end of the cycle, and accounting for the costs and results of each hedge within the same cycle. Such incentive problems are minimized if the GPIM's sharing rules provide consistent incentives under all circumstances, avoiding tolerance bands, caps, and variable sharing percentages.

The examples of pitfalls described in this section are some of the most common compromises to GPIM design principles that lead to distorted incentives and opportunities for the utility to increase its GPIM award through actions that are contrary to the interests of customers. How frequently these opportunities arise, the strength of the distorted incentive when they do arise, and the magnitude of the impact on consumers will depend upon other GPIM characteristics and the particular utility circumstances.

GPIM Design: Summary and Recommendations

The above discussion of GPIM elements and common pitfalls suggests design principles that lead to strong and undistorted incentives that align utility and customer interests. The discussion suggests that GPIMs are typically focused on providing incentives for low-cost short-term procurement, and their designs should apply a strong and equal incentive to all costs and revenues related to this objective. The incentives should not be blunted by caps on awards or large tolerance bands. GPIMs should use a benchmark that adjusts to external conditions such as market prices and load levels, but is independent of actual utility procurement choices (an exogenous benchmark); the benchmark should approximate the cost resulting from a reasonable procurement strategy. GPIMs with such designs provide strong incentives to procure gas supplies at least cost, and only reward actions that lead to lower gas cost. These concepts are summarized in more detail in the accompanying box.

The importance of each design principle, and the potential consequences of compromising one principle in favor of others, will depend upon particular utility circumstances. For instance, to the extent a utility has very little flexibility with regard to certain actions, incentives around these actions, and whether they are strong or weak or distorted, are less important. If there is little chance that prices at various available purchasing points will diverge significantly, using a fixed weighting of purchase locations is unlikely to be a problem. Applying different incentives to different cost categories, or no incentive to some cost categories, raises less of a problem to the extent there is little ability to substitute between the various costs.

Under many circumstances, the main challenge in designing a GPIM benchmark will be to come up with a formula that adapts to the most significant, changeable external conditions (such as load levels and relative prices), while keeping it exogenous (that is, not using actual utility purchase quantities by location, time or type), and without making the formula excessively complex. As mentioned earlier and shown in Appendix 1, in the case of many GPIMs, an exogenous benchmark has been compromised by the use of actual utility purchase quantities by time, location and/or type in the benchmark, rather than values determined in an exogenous manner independent of utility choices. In at least some instances, this probably reflects a concern that use of an exogenous benchmark defined with fixed purchase quantities by time, location or type could lead to large and undeserved awards as a result of rather straightforward optimization of purchases. Alternately, an exogenous benchmark could determine purchase quantities using a more complex formula that takes into account relative prices and other relevant factors; however, this would be more complex. Using actual purchase quantities in the benchmark keeps the benchmark cost close to actual cost, avoiding the potential for undeserved windfall awards, while also keeping the benchmark simple and avoiding the need to define a more complex formula to determine benchmark purchase quantities.

In one instance (the design of SoCalGas' incentive mechanism), use of an exogenous benchmark was apparently considered and rejected, and actual purchase quantities are being used in the benchmark to this day, because of this type of concern under the particular utility circumstances at the time (SoCalGas' substantial flexibility to optimize purchase locations, and uncertainty about the quantity of transportation available from various basins and relative prices at various locations). [24] The California Office of Ratepayer Advocates (ORA) concluded that under SoCalGas' circumstances, an exogenous benchmark would be "inappropriate, risky, and unappealing", although apparently only simple forms of an exogenous benchmark with fixed weights or sequencing by location were considered and rejected.[25] On the other hand, the previous section identified the potentially serious incentive problems that can result from the use of actual purchase quantities in the benchmark (pitfall numbers three through seven), and the SoCalGas mechanism exhibits most of these incentive problems and corresponding gaming opportunities. It is unclear to what extent these drawbacks were understood and considered when the choice was made to apply a non-exogenous benchmark, as ORA's annual reports reviewing SoCalGas' incentive mechanism do not reflect an awareness of these incentive problems and gaming opportunities.[26]

24 Jacqueline Grieg and R. Mark Pocta, Office of Ratepayer Advocates of the California Public Utilities Commission, Rebuttal Testimony (Redacted), Order Instituting Investigation Phase I.A, Docket No. I.02-11-002, April 5, 2004.

25 Id, p. 4.

26 Monitoring and Evaluation Report of Southern California Gas Company's Gas Cost Incentive Mechanism for April 1, 2005 through March 31, 2006, Division of Ratepayer Advocates, California Public Utilities Commission, Docket No. A.06-06-017, October 12, 2006.

Recommended GPIM Design Principles and Characteristics

1. **Provide Equal Incentives For Interrelated Costs and Revenues**: All inter-related and substitutable actions, costs and revenues should have equal incentives applied to them; this provides broad-ranging incentives, and avoids creating opportunities where the utility may be able to maximize less-incented costs to allow optimization of costs or revenues to which stronger incentives apply.
2. **But Focus on Objective of Low Gas Cost; Exclude, or Include Targets For, Hedging**: GPIMs are about low gas cost; incentives for achieving other objectives, such as reliability or price stability, cannot effectively be created within a GPIM, nor should a GPIM create incentives that jeopardize or conflict with these other objectives. Consequently, firm capacity holdings for reliability, and target quantities and a schedule for hedging, should be agreed upon in advance and reflected in the GPIM benchmark (so that holding the required capacity and meeting the targets result in no award or penalty). Or, hedging costs and results can remain entirely outside of the incentive mechanism.
3. **Define the Benchmark to Adapt to Uncertain External Conditions**: The goal should be to provide incentives for actions under utility control while avoiding undue exposure to uncertainties outside of utility control, such as load levels and market prices. That would lead to undeserved "windfall" awards or large penalties, and the exposure to risk could adversely affect utility decision-making.
4. **Define the Benchmark To Approximate a Reasonable Strategy -- Not Too Easy to Beat**: Avoid rigid assumptions about purchase locations; include estimates of offsetting revenues from capacity release and off-system gas sales; etc.
5. **But Keep the Benchmark Exogenous To Avoid Weak or Distorted Incentives, Gaming**: The benchmark calculation should be invariant to actions of the utility, so that awards are earned only by lowering gas cost, not raising the benchmark, and incentives are created for all aspects of procurement decision-making. Avoid reflecting the actual locations, timing or types of purchases in the benchmark, or use of other parameters that are affected by the utility's actual choices.
6. **Set Sharing Rules to Provide Strong, Symmetric Incentives Under All Conditions**: The sharing rules should be set to balance the strength of incentives, the likelihood of relatively large deviations between actual and benchmark gas costs, the utility's risk attitude, and other factors. Variable or asymmetric sharing rules, tolerance bands, and caps distort and blunt incentives, and should be avoided.
7. **Meanwhile, Try To Keep It Simple**: A less complex approach will be less costly to monitor and may reduce the chance of misunderstandings, disputes and unintended incentives.

Periodic Review and Assessment of GPIM Results and Design

The regulatory process for GPIMs generally involves the utility making an annual filing in which it reports its actual costs, and calculates the benchmark gas cost and the resulting GPIM incentive award or penalty. The filing is reviewed by staff of the state regulatory commission or the office of the ratepayer advocate, and the award or penalty, after any necessary adjustments, is approved and reflected in future customer rates through the utility's PGA. The structure or parameters of the GPIM and its benchmark may also be reviewed and adjustments made at the same time.

In principle, strong, well-aligned incentives provided by a GPIM, or a well-structured gas supply and asset management agreement, reduce the need for detailed regulatory review of the reasonableness of a utility's performance of the gas procurement function and of the resulting gas costs. State regulatory policies differ on the extent to which reasonableness reviews are considered needed and appropriate when an incentive mechanism is in place. As examples, according to utility tariffs, the gas procurement incentive mechanisms are considered to "replace" reasonableness reviews in California and Tennessee, while in Missouri tariffs declare the state commission's authority to determine the prudence of gas procurement efforts despite the incentive mechanism.

However, as noted above, under many GPIMs there are some procurement-related cost components, and some aspects of procurement decision-making, that are not subject to GPIM incentives. For decision-making related to costs or revenues that remain outside of the GPIM (or, equivalently, for which the actual cost or quantity values are included in the benchmark, eliminating any incentives), traditional regulatory review would seem to remain appropriate.

For instance, as described in earlier sections, if a GPIM uses actual net purchases by time and location in the benchmark, it provides, at best, no incentive to optimize purchase locations or the timing of storage injections (as described in an earlier section under pitfall numbers three and five, respectively), and may well provide distorted incentives with regard to these choices. A traditional regulatory review of the prudence of the utility's choices in this regard would seem to be appropriate under these circumstances.

Also, if the GPIM results in no award or penalty because of a cap or tolerance band, and the utility was likely able to anticipate this result for some time before the end of the cycle, it faced weak or non-existent incentives for some period of time. Somewhat greater scrutiny of the period when incentives were not effective may be warranted.

This paper has also noted that some GPIM designs provide distorted incentives for some decisions, and can provide opportunities for the utility to increase its incentive award at the customers' expense. In particular, this can occur if unequal incentives apply to interdependent cost categories, or if the benchmark is not exogenous, as occurs if actual purchase quantities or percentages by time, location or type are used in calculating the benchmark. To the extent a GPIM provides distorted incentives and gaming opportunities, the need for regulatory review of the affected aspects of utility decision-making is actually greater than under traditional regulation with no direct incentives at all. The review can be focused on those aspects of procurement for which incentives may be distorted, to determine that the utility did not act in a manner significantly contrary to customers' interests to increase its award under the GPIM.

However, under many circumstances it may be difficult or impossible to ascertain whether the utility acted in a manner contrary to its customers' interests under the influence of distorted incentives created by its GPIM. Referring back to the example in Figure 1, under which lower-cost supply alternatives were available in Basin A, but the utility could earn a larger award with purchases from Basin B: If the utility took advantage of the Basin B offer, increasing its award but also increasing the cost to customers, the fact that a lower-cost offer had been available at Basin A would not be apparent from the utility's GPIM filing; indeed, the utility may have no record at all of such offers that it rejected. For this and other incentive problems created by poor GPIM designs, it could be very difficult to determine whether or not the utility had frequently acted contrary to its customers' interests, and it could require detailed knowledge of the market that is not readily available, especially months after-the-fact. Thus, a poorly structured GPIM that provides distorted incentives and profit opportunities not available under traditional cost of service regulation can increase the incentive for and risk of utility actions that are contrary to the customers' interests, while the typically limited scope of a GPIM review could make it very unlikely that such misconduct could be identified after the fact.

Furthermore, our review of various regulatory audits of GPIM results, of regulatory commission orders approving the associated awards, and of the structure of the corresponding GPIMs, suggests that in many instances, the regulatory staff reviewing the GPIM filing may not be adequately reviewing utility actions to ensure that exploitation of a GPIM's shortcomings has not taken place to a significant extent. The limited scope of these reviews (typically entailing little more than verification of costs and calculation of benchmarks and awards), and statements about the ratepayer savings resulting from the incentive mechanisms (generally not qualified with some acknowledgement of a GPIM's limited scope or imperfect incentives), suggest that in some instances the responsible regulatory staff may be unaware of the full extent of a GPIM's shortcomings, the areas where it can provide weak or distorted incentives, and the full scope of opportunities to increase the utility award at the customers' expense.

In most instances, regulatory staff reviews and commission orders on GPIMs reflect the assumption that if actual costs are below the calculated GPIM benchmark cost, this implies that customers have benefited, the utility's actions were reasonable, and there is no need for a detailed review. A utility operating under a GPIM often will interpret the difference between the benchmark gas cost and actual gas cost as "savings" that it shares with customers, suggesting that it reflects superior utilty performance for which the GPIM deserves credit. Such claims are often echoed by the regulatory commission staff or consumer advocate staff responsible for reviewing the GPIM filing,[27] and the claims are often reflected in the commission order approving the incentive award.[28]

Concluding that all is well with the GPIM if actual costs are below the benchmark may be reasonable if the GPIM is well-structured with an exogenous benchmark that approximates a reasonable procurement strategy and is not too easy to beat. However, we find that very few GPIMs live up to this standard. Because many GPIM benchmarks are not exogenous and/or the benchmarks use simple formulas and are quite easy to beat under many circumstances, the fact that actual costs are below the benchmark is not sufficient to even conclude that procurement actions, and the resulting costs, have been reasonable. A somewhat more detailed review is necessary.

For GPIMs with non-exogenous benchmarks, the magnitude of the difference between benchmark and actual costs may partially reflect utility actions that raised the benchmark. For GPIMs with inflexible or overly simple benchmarks, the difference between benchmark and actual costs may reflect flaws in the benchmark rather than an inspired procurement strategy. Consequently, while the utility may have achieved "savings" relative to its benchmark formula, it may not have achieved savings relative to the procurement strategy it would have pursued absent the GPIM incentives, or relative to a merely reasonable procurement strategy that another, similarly situated utility might have pursued. Essentially, the comparison of actual to benchmark gas costs, given that GPIMs generally incorporate simplified, imperfect benchmarks, does not necessarily tell us whether or not the utility performed well, or whether the GPIM has benefited customers.

Consequently, there is a need for the GPIM review process to drill down and identify how utility procurement differed from that assumed in the benchmark, and/or how it differed from what would have been expected under traditional regulation without incentives. The primary drivers and components of the difference between benchmark and actual costs should be determined, including identification of any significant gains or losses at some time that may have been offset by other losses or gains during the same GPIM cycle. The review should also separately review any aspects of utility decision-making to which incentives are not applied, or for which the actual choices are reflected in the benchmark. Such analysis could reveal that the main sources of differences between benchmark and actual costs may have little to do with the GPIM incentives or the quality of utility performance, and may simply reflect the over-simplified assumptions inherent in the benchmark.

Such reviews may suggest necessary changes to the GPIM structure and benchmark for future GPIM cycles. However, regulatory commissions should be committed to following through on the regulatory bargain and approving incentive awards consistent with an existing GPIM, even if those awards are considered largely "undeserved", except under extraordinary circumstances, such as when there is a finding of utility misconduct.

GPIM Review and Assessment: Recommendations

In light of the difficulty in achieving satisfactory GPIM designs and accurately assessing GPIM results, we recommend that periodic GPIM reviews include the following:

1. By way of introduction, a detailed discussion of the GPIM's structure, scope and incentives (or citation to an earlier such discussion). From this discussion it should be clear for which procurement-related decisions the GPIM creates strong, well-aligned incentives, and for which aspects of procurement decision-making the incentives are weak and gaming opportunities may be present. To the extent the GPIM design does not create strong well-aligned incentives (for instance, to the extent it exhibits any of the pitfalls identified in this paper), the approach to reviewing these aspects of procurement decision-making would be identified.

27 See, for example, Monitoring and Evaluation Report of Southern California Gas Company's Gas Cost Incentive Mechanism for April 1, 2004 through March 31, 2005, Office of Ratepayer Advocates, California Public Utilities Commission, Docket No. A.05-06-030, Nov. 30, 2005 (p. 1-1, "ORA's review also confirmed that application of the sharing mechanism approved in D.02-06-023 results in a ratepayer benefit of $28.9 million and a shareholder award of $2.5 million" and p. 1-6 Table 1-2, summarizing "Total Gas Cost Savings For Ratepayers").

28 See, for example, Order Allowing Incentive Gas Supply Procurement Plan Award and Granting Extension of Plan, Iowa Utilities Board, Docket No. RPU-94-3, Nov. 29, 2004 (p. 3, "Through the IGSPP, MidAmerican customers have realized a savings, relative to the reference price, of $58.4 million …").

2. In addition to the main section of a GPIM review that validates actual costs and calculates the benchmark and award/penalty, more detailed review and analysis should be included for those aspects of procurement decision-making for which the GPIM does not create effective incentives. This will be highly specific to the particular GPIM structure and incentive problem. For instance, if the GPIM uses actual net purchases in the benchmark reflecting actual choices of purchase locations and the timing of storage injections, a separate review of these choices is needed. Did the utility appear to generally make the maximum possible use of the lowest cost supply at all times? Did the utility appear to generally inject gas into storage according to a schedule that was most economical for customers? If not, were there valid reasons for the choices made at the time?

   The need for and level of detail of such reviews would reflect the potential scope for actions that could have substantial impacts contrary to the customers' interests; if the scope for unreasonable conduct was very limited (perhaps by a lack of flexibility and discretion in the utility's decision-making, or by market conditions such that exercise of the utility's discretion could not have had a significant adverse impact on customers), the review could be deemed unnecessary.

3. A GPIM review should also include an evaluation of how the utility achieved the differences between actual and benchmark costs; components might include optimization of purchase locations, optimization of storage use, purchases at prices below benchmark indices, revenues from capacity release and off-system gas sales, and so forth. The analysis should further identify whether the savings were achieved over many transactions spread over time, or perhaps through only a few transactions or concentrated in a single month or season. The GPIM review should also include an assessment of the GPIM benchmark under the specific market conditions that occurred during the GPIM accounting period. Did the benchmark correspond to a reasonable purchasing strategy, such that achieving costs below benchmark are deserving of an award? Or was the benchmark easy to beat under the particular market conditions that occurred? This assessment might lead to a conclusion regarding whether and to what extent the GPIM benefited consumers during the evaluation period.
4. A GPIM review should also include a discussion of design issues and possible modifications or enhancements, based on the assessment of results. This might include enhancements to: (a) extend the GPIM's incentives to a broader range of procurement-related decisions; (b) improve its structure to address areas where it provides weak or distorted incentives (with a discussion of the tradeoffs of various modifications); and/or (c) better balance utility and customer interests and reduce risks.

Final Observations

A GPIM that provides strong incentives for a broad range of procurement-related costs and revenues, using a benchmark that is both exogenous and adaptive to external circumstances, can benefit consumers through lower gas costs and reduced need for regulatory oversight of the procurement function. A GPIM can elicit more active use of utility storage and other assets, which can contribute to market efficiency and mitigate market volatility, benefiting both utility customers and the broader market. Incentive mechanisms also can encourage hedging to some extent. If a target level and schedule of hedging is reflected in the benchmark, the utility minimizes its risk by staying close to the targets. The potential benefit to consumers from an incentive mechanism depends upon the scope of the opportunities for a utility to reduce gas cost by superior performance, whether a GPIM can be fashioned to provide strong incentives to achieve superior performance, and the extent to which a GPIM accommodates significant administrative savings in the regulatory process.

In practice, GPIM designs reflect tradeoffs between competing principles, and the best balance between the various principles will depend upon each utility's particular circumstances. Under some circumstances it may be difficult to design a GPIM that provides sound incentives while not exposing the utility to substantial risks, or customers to the potential cost of windfall awards, without significant complexity in the benchmark formula. Accordingly, GPIMs may not be appropriate for some utility circumstances. This will also depend upon utility and regulatory attitudes toward various outcomes; if a utility is highly risk-averse, or its regulator highly averse to the chance of large and perhaps somewhat undeserved awards in some years, a GPIM may be a poor fit. If, instead, the parties take the view that the incentive mechanism is expected to be fair over the long run, and short-run variability is acceptable, an effective mechanism may be possible that is not unduly complex.

Appendix 1: Summary of Structures of Gas Procurement Incentive Mechanisms

Utility:	1. PG&E (CA)	2. SoCalGas (CA)	3. MidAmerican (IA)
Gas Procurement Incentive Mechanism:	Core Procurement Incentive Mechanism (CPIM)	Gas Cost Incentive Mechanism (GCIM)	Incentive Gas Supply Procurement Plan (IGSPP)
Scope (utility actions, costs and revenues to which incentives are applied)	Procurement costs including capacity release and gas sales	Procurement costs including capacity release, gas sales and hub-services revenues	Pipeline reservation, supply, storage, and transportation costs; separate incentives for gas sales, and capacity release
Period for which incentives computed	Annual (Nov. 1 to Oct. 31)	Annual (Apr. 1 to Mar. 31)	Semi-annual (May-Oct., Nov.-Apr.)
Benchmark – prices used	First-of-month and daily indices	First-of-month indices	Monthly and daily indices, prices in supply contracts, FERC tariff or past discounted pipeline rates
Benchmark – quantities used	Determined by formula based on load and prices	Actual purchase quantities by month and location, net of gas sales	Actual volumes by month and location
Benchmark – treatment of storage	Assumed storage injection and withdrawal pattern	Actual storage use is reflected in net purchase quantities used in benchmark	Actual storage use is reflected in net purchase quantities used in benchmark
Is the benchmark exogenous?	Yes – formula independent of company's actual purchasing decisions	No – actual purchase quantities by month and location used	No – actual purchase quantities used
Treatment of hedging	Hedges flow through the incentive mechanism, putting the utility at risk; requests have been made for authority to do hedges outside the mechanism	Hedges flow through the incentive mechanism, putting the utility at risk; requests have been made for authority to do hedges outside the mechanism	Hedging program is outside of incentive mechanism
Tolerance band (v. benchmark)	99% - 102%	99% - 102%	99.5% - 102.5%
Sharing rule (utility %)	For awards, 25% and capped; 50% for penalties	For awards, 25% up to 5% below benchmark, then 10%, and capped; 50% for penalties	50% for first 3% beyond tolerance band, capped at dollar value; for capacity release and off system sales, 50% goes to company
Other key features		Hub-services revenues reduce actual cost but are not reflected in benchmark	Incentive for lower pipeline rates; ratcheted down over time

Appendix 1: Summary of Structures of Gas Procurement Incentive Mechanisms (cont'd)

Utility:	4. NIPSCO (NiSource) (IN)	5. Indiana Gas (Vectren) (IN)	6. LG&E (KY)
Gas Procurement Incentive Mechanism:	Gas Cost Incentive Mechanism (GCIM) and Alternative Regulatory Plan (ARP)	Gas Cost Incentive Mechanism (GCIM); capacity release program; affiliate Proliance is supplier	Experimental Performance Based Rate Mechanism
Scope (utility actions, costs and revenues to which incentives are applied)	Commodity only; also sharing rules for demand charge reductions and capacity release	Commodity only; separate capacity release program	Gas commodity, transportation costs, off-system sales
Period for which incentives computed	Monthly	Monthly	Annual (Nov.1 to Oct.31)
Benchmark – prices used	First-of-month and daily reflecting actual purchase quantity	First-of-month and daily reflecting actual purchase quantity	Combination of daily, weekly and monthly price indices; pipeline rates approved by FERC; off-system sales net revenue
Benchmark – quantities used	Actual purchases by location and monthly/daily	Actual purchases by location and monthly/daily	Actual purchase quantities by location
Benchmark – treatment of storage	Not applicable – monthly mechanism	Fixed injection schedule, FOM prices used.	Actual storage use is reflected in purchase quantities used in benchmark
Is the benchmark exogenous?	No – actual purchase by location, FOM/ daily market used	No – actual purchases by location, FOM/daily market, for commodity or storage	No (uses actual volumes)
Treatment of hedging	Separate from incentive program	Separate hedging program outside of incentive mechanism	None in benchmark; company at risk for hedges
Tolerance band (v. benchmark)	None	None	None
Sharing rule (utility %)	Commodity: 50%; interstate transportation demand charge reductions: 50%; capacity release: 15%	Commodity: 30/50/70% if differential is 0-2/2-4/over 4%; 100% of storage optimization benefit goes to Proliance	25% up to 4.5% of benchmark costs; 50% in excess of 4.5%
Other key features		Unused entitlements capacity release: utility auctions 50%, keeps 15% of revenue; other 50% goes to Proliance for fixed dollar fee	

Appendix 1: Summary of Structures of Gas Procurement Incentive Mechanisms (cont'd)

Utility:	7. Laclede Gas (MO)	8. New Jersey Natural Gas (NJ)	9. NYSEG (NY)
Gas Procurement Incentive Mechanism:	Gas Supply Incentive Plan (GSIP); also, company retains 100% of off-system sales and capacity release revenues after offset	Basic Gas Supply Service (BGSS) incentive programs	Gas Cost Incentive Mechanisms (GCIM 1 for NYSEG, and GCIM 2, for parent Energy East and supplier BP Energy)
Scope (utility actions, costs and revenues to which incentives are applied)	Procurement costs including financial hedges, but not demand charges, storage costs; off-system sales, capacity release are separate	Off-system sales, capacity release, on-system interruptible sales, storage purchases, risk management	GCIM 1: NYSEG stand-alone capacity release and off-system gas sales; GCIM 2: Energy East/BP Energy joint optimization of supply, storage, transportation, turn back savings
Period for which incentives computed	Annual (Oct. to Sept.)	Annual	Annual (Apr. 1 to Mar. 31)
Benchmark – prices used	First-of-month	Not applicable	GCIM 1: Not applicable; GCIM 2: Determined by utility supply plans
Benchmark – quantities used	Fixed weights by location; actual quantities by month	Not applicable	GCIM 1: Not applicable; GCIM 2: Determined by utility supply plans
Benchmark – treatment of storage	Actual storage use is reflected in purchase volumes used in benchmark	A storage incentive is defined relative to a benchmark based on NYMEX forward prices	Not specified (but savings are split)
Is the benchmark exogenous?	No (uses actual monthly purchase volume)	Unknown	Yes (GCIM 2: benchmark is the utility supply plans, which supplier optimizes)
Treatment of hedging	None in benchmark; financial hedges can contribute to reward (but not penalty)	Benefits of Financial Risk Management program shared between customers and the company	Outside of incentive mechanisms
Tolerance band (v. benchmark)	None	None	None
Sharing rule (utility %)	10%, reduces to 1% once award reaches $5 million (awards only). Incentive payments only if cost between $4 and $7.50/MMBtu, and no penalties	Off-system sales and capacity release, 15%; Financial Risk Management, 20%; on-system interruptible sales, 10%; interruptible balancing, 5%; storage, 20%	GCIM 1: 20% of non-migration capacity release, local production and off-system sales; GCIM 2: 50% with minimum customer savings, or 25% if savings less than estimated standalone savings
Other key features		Incentives are not found in tariff and are under review	Statistical model used to distinguish GCIM 1 and GCIM 2 transactions, quantify savings

Appendix 1: Summary of Structures of Gas Procurement Incentive Mechanisms (cont'd)

Utility:	10. Avista (OR)	11. New England Gas (RI)	12. Atmos (TN)
Gas Procurement Incentive Mechanism:	Purchased Gas Cost Adjustment Provision	Gas Procurement Incentive Plan (GPIP), Asset Management Incentive Plan (AMIP)	Performance Based Ratemaking Mechanism (PBRM), with two parts: Gas Procurement and Capacity Management
Scope (utility actions, costs and revenues to which incentives are applied)	Commodity costs, financial transactions, storage, off-system sales; a separate incentive applies to capacity release.	"Discretionary" NYMEX purchases before delivery month (GPIP); various fixed costs (AMIP)	Gas commodity; storage and transportation capacity release
Period for which incentives computed	Annual (Oct. to Sept.)	Monthly	Monthly
Benchmark – prices used	Estimated monthly average costs set before the year based on contract prices	Average cost for each delivery month of NYMEX hedges placed over 24 months	Published monthly and daily market price indices
Benchmark – quantities used	Prior year normalized purchases, adjusted to actual total sales	"Discretionary" purchase quantities	Actual purchases by month and location, actual storage injection quantities
Benchmark – treatment of storage	Not reflected explicitly in benchmark	Not applicable (calculated monthly)	Not included; monthly purchases are benchmarked
Is the benchmark exogenous?	Yes; prices are set in advance, volumes are based on prior year	No (uses actual discretionary purchase volume)	No – actual purchase quantities used
Treatment of hedging	Forward purchases reflected in benchmark (no incentive); other financial transactions flow through mechanism	Benchmark has 24-month hedging schedule	Cost and savings flow through the incentive mechanism
Tolerance band (v. benchmark)	None	None	97.7%-102%
Sharing rule (utility %)	10% of commodity-related costs (including storage, financial transactions, off-system sales); 20% of capacity release revenues in excess of pipeline tariff rate on a transaction basis.	10%, maximum \$1 million award, \$0.5 million penalty (GPIP); 10% or 20%, maximum \$.4 million award (AMIP); AMIP incentive tied to GPIP result	Commodity: 50%; Capacity management: 10%
Other key features			Annual cap on overall utility incentive savings and costs

Appendix 1: Summary of Structures of Gas Procurement Incentive Mechanisms (cont'd)

Utility:	13. Nashville Gas (TN)	14. Alliant/Wisc. P&L (WI)	15. Superior WL&P (WI)
Gas Procurement Incentive Mechanism:	Performance Incentive Plan with two parts, Gas Procurement and Capacity Management	Gas Cost Recovery Mechanism (GCRM)	Incentive Gas Cost Recovery Mechanism (GCRM)
Scope (utility actions, costs and revenues to which incentives are applied)	Gas commodity and off-system sales; storage and transportation capacity release	Procurement costs including capacity release and gas sales	Commodity costs, capacity release, gas sales, but not transportation or storage reservations
Period for which incentives computed	Monthly	Annual (Nov. 1 to Oct. 31)	Annual (Nov. 1 to Oct. 31)
Benchmark – prices used	Published monthly and daily market price indices	First-of-month indices weighted by contracted volumes	First-of-month indices (+2.5% for flexibility, reliability)
Benchmark – quantities used	Actual purchases by time, location, and market (daily/monthly)	Determined by load, firm transportation capacity rights, planned storage withdrawals	Forecast volumes from Gas Supply Plan
Benchmark – treatment of storage	Not included; monthly purchases are benchmarked	Planned storage injection and withdrawal quantities	Planned storage injections
Is the benchmark exogenous?	No – actual purchase quantities by location and type used	Yes	Yes
Treatment of hedging	Cost and savings flow through the incentive mechanism	Cost and impacts are outside of incentive mechanism	Not included (does not engage in hedging)
Tolerance band (v. benchmark)	None	None	98.5% - 101.5%
Sharing rule (utility %)	Commodity: 50%; Capacity: 0% for small savings up to 50% if savings >3% of demand costs	50%	50% up to 4% above or below benchmark (capped)
Other key features	Annual cap at $1.6 million overall company gain or loss; company assigns firm assets to "Asset Managers" in exchange for a fixed fee	Fixed dollar offsets for capacity release or off-system gas sales; certain cost elements are flowed through	Fixed dollar offsets for capacity release or off-system gas sales; certain cost elements are flowed through

Appendix 2: Summary of Structures of Gas Portfolio and Asset Management Agreements

Utility:	1. Indiana Gas/ Proliance (IN)	2. Virginia Natural Gas/ Sequent (VA)	3. NYSEG/ Energy East/ BP Energy
Utility/supplier agreement	Gas Sales and Portfolio Administration Agreement	Gas Purchase and Sale Agreement; Asset Management and Agency Agreement, includes incentive mechanism	NYSEG and other Energy East affiliates have "strategic alliances" with BP Energy as gas portfolio manager
Other utilities involved in the same or similar arrangements	Similar agreements with Southern Indiana G&E, City of Indianapolis, Citizens Gas and Coke	Sequent also has asset management agreements with five other AGL LDCs, and other customers	Energy East affiliates Rochester Gas and Electric, Southern Connecticut Gas, Connecticut Natural Gas, Berkshire Gas, Maine Natural Gas
Is supplier affiliated?	Yes, with Indiana Gas and Southern Indiana G&E (parent: Vectren)	Yes	No
Term	2006-3/31/2011	10/05 to 10/08	4/04 to 4/07
Scope of service provided to utility	Full requirements supply	Full requirements supply	Gas purchasing; optimizing Energy East companies' portfolios and upstream transportation and storage assets
Assets managed by supplier	Supplier receives 50% of excess capacity	Transportation, storage, peaking	Upstream transportation and storage
Charges for supply service provided to utility	Utility pays reservation costs; commodity cost per utility's GCIM; storage gas cost based on fixed injection schedule and FOM prices	Utility pays based on index prices, with quantities set through utility's "virtual dispatch"; also, shares savings if supplier's actual dispatch is lower cost	For NYSEG, supplier's fee is based on the level of savings from optimization of the Energy East portfolio, with guaranteed level of savings (see NYSEG's "GCIM 2" in previous Appendix)
Compensation to utility for use of assets	Fixed dollar amount agreed in advance	Fixed dollar amount set in advance plus portion of net margin from capacity release, off-system sales, transportation and storage optimization	For NYSEG and Rochester, shared savings; nature of agreements with other Energy East companies unknown
Supplier/utility coordination	Daily communication for supply planning	Monthly, daily "virtual dispatch"; utility group for oversight of performance	Daily communication for supply planning
Other features		Detailed reporting of actual daily purchases and their costs	Statistical model applied to identifying those transactions for which savings are shared under this arrangement, and to quantifying the savings

Appendix 3: Links to Gas Procurement Incentive Mechanisms

Most of these links are to the company's complete gas tariff, while others are to a regulatory commission order that includes the incentive mechanism as an attachment.

This is not a comprehensive list of all existing gas procurement incentive mechanisms; in particular, in some of the states represented on the list, other gas distribution companies in the state also have incentive mechanisms.

State	Company	Link to document defining incentive mechanism or agency agreement
CA	PG&E	http://www.pge.com/tariffs/pdf/GPSC.pdf (p. 14)
CA	San Diego G&E	http://www.sdge.com/tm2/pdf/PBRVII.pdf
CA	SoCalGas	http://www.socalgas.com/regulatory/tariffs/tm2/pdf/PS-VIII.pdf
CA	Southwest Gas	http://www.swgas.com/rates/catariff/cover/CA_Gas_Tariff.pdf (p. 37)
IA	MidAmerican	(not online; some details can be obtained from Steve.Zimmerman@iub.state.ia.us)
IN	NIPSCO	http://www.in.gov/iurc/portal/Guest.aspx?tabid=7 (then Search Case 42884)
IN	Indiana Gas Co.	http://www.in.gov/iurc/portal/Guest.aspx?tabid=7 (then Search Case 42973)
KY	Columbia Gas KY	http://www.columbiagasky.com/pdf/Sheet%20No%2050.pdf
KY	Louisville G&E	http://www.eon-us.com/rsc/lge/lgeresgas.pdf
MD	Baltimore G&E	http://www.bge.com/vcmfiles/BGE/Files/Rates and Tariffs/Gas Service Tariff/Brdr_2.doc
MO	Laclede Gas	http://www.lacledegas.com/customer/PDF_rates/PurchasedGasAdjustment.pdf (p. 21)
NJ	New Jersey N.G.	http://www.state.nj.us/bpu/wwwroot/energy/GR05060488_20060413.pdf
NY	NYSEG	http://www.nyseg.com/nysegweb/webcontent.nsf/Lookup/Psc90/$file/Psc90.pdf
NY	Rochester G&E	http://www.rge.com/rgeweb/webcontent.nsf/Lookup/PSC16=56_84/$file/PSC16=56_84.pdf
OR	Avista	`http://www.avistautilities.com/assets/tariffs/or/OR_462.pdf
OR	Cascade	http://www.cngc.com/post/rates_tariffs/oregon/0177_Purchased_Gas_Cost_Adjustment_ Provision.pdf
PA	UGI	http://www.ugi.com/gas/tariff/GStariff.pdf
RI	New England Gas	http://www.ripuc.org/eventsactions/docket/3436-NEGasOrd18273(6-16-05).pdf (apdx)
TN	Atmos Energy	https://www.atmosenergy.com/download/tariffs/tn_aec_tariff.pdf
TN	Nashville Gas	http://www.nashvillegas.com/rates/tariffs/tn/Rate_Sch._316-Performance_Incentive_Plan.pdf
TN	Chattanooga Gas	http://www.chattanoogagas.com/Repository/Files/cgc_tar_2006.pdf (p. 53)
VA	Virginia N.G.	http://docket.scc.virginia.gov:8080/vaprod/DOCUMENTS.ASP?MATTER_NO=119533 (incentive mechanism is defined in agreements attached to staff report in this docket)
WI	Alliant/Wis.P&L	http://alliantenergy.com/docs/groups/public/documents/pub/p012625.pdf#page=7
WI	Madison G&E	http://www.mge.com/images/PDF/Gas/Rates/GasRates.pdf (p. 90)
WI	Superior WP&L	http://psc.wi.gov/pdffiles/tariffs/gas/5820.pdf (p. 75)
WI	Wisconsin Gas	http://www.we-energies.com/pdfs/tariffs_vol7/WGCtariffbk_vol7.pdf (p. 55)
WI	Wisconsin Elec.	http://www.we-energies.com/pdfs/tariffs_volXVI/WEGOtariffbk_volXVI.pdf (p. 58)

Appendix 4: Arithmetic of Gas Procurement Incentive Mechanisms

This appendix describes a generic benchmark incentive mechanism arithmetically, using this representation to examine its incentive properties. In particular, it demonstrates how an exogenous benchmark leads to correct incentives, while a benchmark that is not exogenous may lead to weak or perverse incentives.

For clarity, the discussion refers to gas costs; however, it is equally applicable to a benchmark mechanism for any other performance measure.

Let

B = the Benchmark value of gas cost
A = the Actual gas cost
s = the fraction or Share of the difference between the benchmark and actual gas cost that the utility receives as an award (or penalty) for achieving costs below (or above) the benchmark; assume no tolerance band is used; $0 <= s <= 1$
R = the utility's reward (penalty)
C = the total Cost borne by customers, which equals actual gas costs plus the award (penalty)

Then:

[1] $R = s(B-A)$
[2] $C = A + R = A + s(B-A)$

Note that if $s = 0$, all costs are passed through and there is no award, thus $R=0$, $C=A$. If $s = 1$, customers always incur the benchmark costs, with the utility keeping all differences between benchmark and actual cost, thus $C = B$, $R = B-A$.

Incentives Created For Specific Procurement Decisions

To see how the incentive mechanism creates an incentive for the utility to take a particular action, let

B0, A0, R0, C0 = benchmark cost, actual cost, award, and cost to consumers, respectively, without the action.
B1, A1, R1, C1 = the same values, if the action is taken.
$\Delta B = B1 - B0$ = impact of the action on the benchmark
$\Delta A = A1 - A0$ = impact of the action on actual costs
$\Delta R = R1 - R0$ = impact of the action on the utility's award (this is the utility's incentive to take the action)
$\Delta C = C1 - C0$ = impact of the action on the cost borne by consumers (identifying whether the action actually benefits consumers or not)

Using equations [1] and [2] above we get

[3] $\Delta R = s (\Delta B - \Delta A)$
[4] $\Delta C = \Delta A + \Delta R = s\Delta B + (1-s)\Delta A$

Incentives with regard to this particular action are "aligned" if ΔR and ΔC have the opposite sign (plus or minus), indicating that if the action lowers cost to customers, it increases the award to the utility. The incentive is perverse if ΔR and ΔC have the same sign, and the incentive is weak if ΔR is very small or zero when ΔC is large.

Incentives Under Exogenous Benchmarks

This description demonstrates the incentive properties when the benchmark is exogenous. If the benchmark is exogenous, $\Delta B = 0$ (the utility action does not affect the benchmark). Then

$\Delta R = - s \Delta A$ (using [3])
$\Delta C = (1-s) \Delta A$ (using [4])

For $0 < s < 1$, ΔR has the opposite sign of ΔA and ΔC, so incentives are aligned. Furthermore, the incentive (potential award) is always proportional to the potential benefit to customers, so the strength of the incentive is consistent.

Incentives Under Non-Exogenous Benchmarks

If instead the benchmark is not exogenous (the utility's action affects the benchmark), there are various possibilities.

If the action affects the benchmark and actual gas costs equally (for example, the cost and revenue impact of the action are included in the benchmark under the design of the incentive mechanism), the incentive with regard to the action will be zero:

$\Delta B = \Delta A$; $\Delta R = 0$; $\Delta C = \Delta A$

If instead the action increases the difference between benchmark and actual costs (even if actual costs increase), the utility's award is increased and there is a positive incentive. Actions that increase the benchmark create an award that reflects some false savings and is at least partially undeserved. For example, assuming the action increases the benchmark and actual costs are unaffected,

$\Delta B > 0$; $\Delta A = 0$; $\Delta R = s\Delta B > 0$

$\Delta C = s\,\Delta B = \Delta R > 0$ the utility's award is entirely at the consumers' expense.

If the action lowers actual costs but also increases the benchmark, the resulting increase in the award may more than offset the reduction in actual cost. Due to the undeserved award, the cost to consumers C may rise even if actual costs A were reduced by the action.

Suppose $\Delta A < 0$ (which is good), and suppose $\Delta B = -\Delta A > 0$. Using [3] and [4],
$\Delta R = -2\,s\,\Delta A > 0$, so the utility has an incentive to take the action.
$\Delta C = \Delta A - 2\,s\,\Delta A = (1 - 2\,s)\,\Delta A$ which will be greater than zero if $s > \frac{1}{2}$.

In this instance, if $s > \frac{1}{2}$, while actual costs are reduced, the award leads to an increase in the cost to consumers, so there is a perverse incentive to take the action.

Incentives When Benchmark Reflects Actual Purchase Quantities

Perverse incentives under an incentive mechanism can result if the benchmark is calculated based on actual net purchase quantities, and monthly indices are used in the benchmark. Under these circumstances, transactions on the daily spot market are implicitly benchmarked using the monthly index price used in calculating the benchmark.

Consider the situation where prices on the daily spot market rise above the monthly index price and a gas sale is contemplated. Suppose the sale is to be replaced in the following month through a purchase on the monthly market, at a price that will equal the monthly price index. Let

Mi = monthly price index for current month (i)
Mj = monthly price index for the next month (j)
P = daily spot market price at the time of the gas sale
(by assumption, P > Mi)

For a gas sale of one unit, the total impact on the benchmark (ΔB) equals the impact of the sale in the current month (by reducing the net purchase quantity one unit) plus the impact of the repurchase in the next month.

$\Delta B = -Mi + Mj$

The impact on actual gas costs also has the two components.

$\Delta A = -P + Mj$

Using [3] and [4],

$\Delta R = s\,(\Delta B - \Delta A) = s\,(P – Mi) > 0$, since by assumption $P > Mi$. So there is a positive incentive for the gas sale.
$\Delta C = \Delta A + \Delta R = (-P + Mj) + s(P-Mi)$

Consumers benefit only if $\Delta C < 0$, which will be the case when

$-P + Mj < -s\,(P – Mi)$

As one example, suppose the sharing rule is such that s = ½. Then consumers benefit only if

$-P + Mj < -½\,(P- Mi)$
$Mj < ½\,(P + Mi)$

Consumers benefit from the transaction only if the forward price Mj is less than the average of the spot price and (lower) current month index (that is, it is closer to the current month index than to the spot price). If, instead, the forward price is closer to the spot price, the cost to consumers increases, even if the transaction itself is profitable, due to the award.

Appendix 5: Examples of Issues and Problems Raised in Regard to Gas Procurement Incentive Mechanisms

Utility	Issues/Problems Raised
Avista Utilities (WA)[a]	Reasonableness of gas supply relationship with affiliate; inability to audit affiliate with the current information provided to the commission; ease with which affiliate earned an incentive award; large benefits to the utility relative to its risk; extent of benefits to consumers
Laclede (MO)[b]	Size of utility awards relative to consumer benefits; structure of mechanism in benefiting consumers; lack of utility documentation on gas procurement activities; impact of incentive mechanism on hedging; treatment of transportation discounts; incentives from "individual, compartmentalized" benchmarks (relative to a comprehensive purchasing program focusing on the delivered cost of gas and reliability)
LG&E (KY)[c]	Sharing rule; capacity release threshold; benchmark calculation, for example accounting for transportation discounts and the NYMEX strip price; treatment of storage sales for off-system transactions; sharing ratios; capacity release threshold
MidAmerican (IA)[d]	Treatment of discounted transportation rates; reward caps; supply cost premium accounting for reservation costs for firm supply
Minnegasco (MN)[e]	Extent of consumer benefits, as measured by rates of the utility relative to other gas utilities in the state over the period of the GPIM; "productivity" offset in benchmark (to reflect market conditions prospectively and to ensure continued improvement in the utility's performance); effect on non-gas costs
NYSEG (NY)[f]	Allocation of transactions and savings between the utility and its parent/suppliers; allocation of fees
Nashville Gas (TN)[g]	Sharing rule for capacity management; treatment of asset management fees in incentive mechanism; scope of ex post audit (e.g., simply verification of utility calculations, or inclusion of analysis and review of mechanism); need for outside consultant to audit the incentive mechanism
NICOR (IL)[h]	Use of low-cost stored gas that increased incentive award; storage credit adjustment; firm deliverability adjustment; sharing percentages for savings and losses; calculation of the benchmark as "an accurate proxy for costs under traditional regulation"
SoCalGas (CA)[i]	Impact of incentives on spot gas sales, hub transactions and storage management
Virginia Natural Gas (VA)[j]	Allegations of mismanagement of assets to detriment of customers under a procurement and asset management agreement with an affiliate
Wisconsin P&L (WI)[k]	Utility awards despite relatively high purchased gas costs; cost treatment of stored gas; ability of staff to audit annual performance; distortions from utility motivation to "beat the benchmark" rather than to reduce purchased gas costs; benefits of incentive mechanism structure to consumers versus traditional cost recovery

(Footnotes for Appendix 5)

[a] Washington State Utilities and Transportation Commission, Sixth Supplemental Order Rejecting Benchmark Mechanism Tariff, Docket No. UG-021584, February 13, 2004.

[b] Missouri Public Service Commission, Report and Order, Case No. GT-2001-329, Tariff No. 200100572, September 20, 2001.

[c] Louisville Gas and Electric Company, Modifications to Louisville Gas and Electric Company's Gas Supply Clause to Incorporate an Experimental Performance Based Ratemaking Mechanism, Case No. 2001-00017, December 30, 2004; and Louisville Gas and Electric Company, Response of Louisville Gas and Electric to the Attorney General's Initial Request for Information, Case No. 2005-00031, February 21, 2005.

[d] Iowa Utilities Board, Memo to Board concerning MidAmerican's proposed reward resulting from its Incentive Gas Supply Procurement Plan (IGSPP), Docket No. RPU-94-3, April 21, 2005; and Iowa Utilities Board, Order Granting Extension of Incentive Gas Supply Procurement Plan, Docket No. RPU-94-3, September 18, 2000.

[e] Minnesota Public Utilities Commission, Report on Performance-Based Gas Purchasing Plans, pursuant to Minn. Stat. § 216B.167, sub. 7 (1995), Docket No. G-008/CI-98-1219, February 1999; and Minnesota Department of Commerce, Comments of the Energy Division of the Minnesota Department of Commerce, Docket No. G011/M-99-1549, January 3, 2000.

[f] State of New York Public Service Commission, Order Approving Gas Cost Incentive Mechanism Methodology, Case No. 01-G-1668, October 7, 2005.

[g] Audit Staff of the Utilities Division, Tennessee Regulatory Authority, Staff Reply to Nashville Gas Company's Response to the Utilities Division's Incentive Plan Account Audit Report, Docket No. 04-00290, May 18, 2005; and Tennessee Regulatory Authority, Order Adopting Incentive Plan Account Filing of Nashville Gas Company for Year Ended June 30, 2004, Docket No. 04-00290, September 6, 2005.

[h] Illinois Commerce Commission, Order on Petition for Permission to Place into Effect Proposed Rider 4, Gas Cost, Pursuant to Section 9-244 of the Illinois Public Utilities Act, Docket No. 99-0127, November 23, 1999; David J. Effron, Direct Testimony, before the Illinois Commerce Commission, Docket Nos. 01-0705, 02-0067, 02-0725 (Consolidated), November 21, 2003; and Richard J. Zuraski, Direct Testimony on Reopening, before the Illinois Commerce Commission, Docket Nos. 01-0705, 02-0067, 02-0725 (Consolidated), November 21, 2003.

[i] Public Utilities Commission of the State of California, Interim Opinion on Phase I.A Issues, Investigation 02-11-040, November 16, 2004 (this draft decision, of which incentive mechanisms were a minor part, was rejected by the CPUC, and no final decision has been issued in the proceeding).

[j] Commonwealth of Virginia State Corporation Commission, Order Approving Affiliate Agreements and Closing Investigation, Case No. PUE-2004-00111, October 31, 2005.

[k] Gail M. Maly, Direct Testimony, before the Public Service Commission of Wisconsin, Docket No. 6680-UR-114, April 4, 2005; and Public Service Commission of Wisconsin, Final Decision on the Application of Wisconsin Power and Light Company for Authority to Increase Retail Electric, Natural Gas and Ripon Water Rates, Docket No. 6680-UR-114, July 19, 2005.

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