A REVIEW OF THE RETAIL TARIFFS OF HYDRO-QUÉBEC DISTRIBUTION

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

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of

Hydro-Québec Distribution

by

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EXECUTIVE SUMMARY

Overview

This report provides Hydro-Québec Distribution (HQD) with an independent review of its retail rates' ability to achieve the goals of rate design in response to a directive from the Régie de l'énergie. The Company asked Christensen Associates Energy Consulting to conduct this review.

This report also investigates a range of current design issues:

- The recovery of fixed costs from mass market customers.
- Pricing for customers interested in distributed generation (DG).
- Pricing of standby generation services for business customers with site generation.
- Customer class segmentation and the use of industry-specific pricing.
- Pricing for customers with competitive alternatives.
- Management of cross subsidy and variations in allowed revenue-to-cost ratio across classes.

Rate Design Principles

The report finds that the traditional criteria for rate design—focusing on pricing for economic efficiency and revenue recovery while retaining stress on rate simplicity, fairness, and the avoidance of cross subsidy—are still timely. HQD has two additional criteria:

- Maintaining the affordability of electricity service to Domestic customers.
- Avoiding deterioration in the competitiveness of Large Power customer rates.

Rates also need to be compatible with Québec's recently released long-term energy policy, which stresses environmental sustainability and energy efficiency, among other objectives.

Additional issues include: 1) impediments to rate rebalancing; and 2) how to achieve rate simplicity.

Domestic Class

HQD's Domestic rate portfolio is in transition, based on the Company's recently filed Tariff Strategy. Rates D and DP are well within residential class rate designs. Rate DT, while unusual, shares design characteristics with demand-response designs like critical-peak pricing (CPP). HQD reports four Domestic class pricing issues.

Fixed Cost Recovery. The industry is exploring several approaches to fixed cost recovery:

- Increases in customer charges and the use of demand charges.
- Use of graduated customer charges to retain low charges for low-usage customers.
- Use of minimum bills.
- Use of other customer information to identify directly those with low income.

The industry has not selected any particular strategy as yet, providing utilities with the opportunity to explore preferred alternatives.

Space Heating. The chief pricing issue for space heating is whether introducing a time pattern to pricing would help to control costs at peak times for a winter-peaking utility. Several utilities are experimenting with demand-response pricing to control summer cooling, with success.

Dual-Fuel Pricing. HQD's Rate DT and the pilot program to solicit demand response via direct load control are in line with industry efforts to introduce short-notice customer response to improve system reserves at critical times. Statistical analysis of summer cooling programs demonstrates that significant response is feasible.

Small Customer Bill Payment Capability. Lifeline rates with cold weather disconnection bans and prepayment rates provide some ways to manage bill payment issues of low-income customers. These do not address the problem of the overall bill amount, though. Targeted customer discounts of a lump-sum variety appear to directly address the issue.

Small and Medium Power Classes

HQD's Rates G and M, including the use of ratchets, are well within industry standard practice. Small business customers tend to be served under energy-only tariffs while demand charges are common for larger customers. Time variation in rates is not a widespread feature.

Some of HQD's rate options—Economic Development Rates and interruptible pricing—are commonly found elsewhere, while the running-in and testing features are less common, perhaps because some utilities deal with such issues on an informal basis. The Additional Electricity Option is a variant of rate designs becoming increasingly available by which customers gain limited access to market-based pricing. HQD's designs meet industry standards. More market-based pricing may help in the future.

Large Power Class

HQD's base rates are well within industry practice, but do not display the variety of rate options that some other utilities display. This appears to be due to the lack of time variation in HQD energy and demand costs relative to other utilities.

Pricing issues for Large Power customers include: 1) the pricing differences between Rates L and LG; and 2) policy with respect to special pricing by industry. Rates L and LG have different structures for pricing peak demand, related to the challenges to system operations that very large customers may pose. The differential pricing of Heritage Pool power is not cost justified but related to the difficulty in maintaining price competitiveness for the Rate L customers.

Possible approaches to this challenge include:

- A review of cost to serve by each rate class. Lower peak coincidence of Rate L customers may justify lower pricing.
- A review of the restriction on rate case price increases to proportional increases. As time passes, costs to serve customers change, suggesting the advisability of greater pricing flexibility.
- Exploration of greater use in pricing of market-based prices. The Additional Energy Option provides access that is relatively inflexible compared with other jurisdictions. Shorter-notice contractions in response to high retail price at times of high wholesale market price (or expansions if low-price periods occur) might offer an opportunity to satisfy revenue requirements while reducing cost on some changes in usage from past levels.

Pricing for specific industries. HQD has tried industry-specific pricing on a limited basis (greenhouses). Other jurisdictions have experimented as well. The practice is not popular with regulators, who regard pricing for broad classes of customers as a way to ensure fairness in ratemaking. HQD is within industry utility and regulatory practice by pursuing rate simplicity by not creating rates for special industries and focusing on portfolio choice that offers customers optional structures that attempt to meet diverse customer needs, regardless of industry.

Other HQD Rate Designs

Economic Development Rate and Load Retention Rate Options. HQD's approach is in keeping with the processes of other utilities. Issues for discounted rates include: 1) distortion of energy prices away from marginal cost, which should serve as a price floor; and 2) the means by which a utility can avoid being asked for discounts by other customers. HQD resolves the latter issue for LRR applicants by requiring that customers achieve other cost savings and satisfy significant documentation requirements.

Interruptible/Curtailable Rates. HQD's rates provide options for amount of interruption and payment for availability and for actual load reduction. This approach is common in the industry. HQD is also introducing a commercial program in the winter of 2016-17 called *Gestion de la demande en puissance* (GDP). This option pays customers for undertaking actions that enable reducing usage when called.

HQD is properly paying customers for availability and price response. A review of pricing might suggest opportunities to improve the timeliness and efficiency of interruptible pricing.

Standby Pricing. HQD's standby tariffs are tailored to customer classes and are well within industry design standards. Non-traditional designs make use of "two-part" real-time pricing to simplify an otherwise complicated design and pricing challenge.[1]

Electric Vehicle Rates. A. Home charging. HQD can follow other utilities' lead by investigating the merits of a time-varying price (that reflects whatever time variation exists in its own marginal costs). Optional variants on this design allow either the utility to use direct load control or short-notice pricing like CPP for times of tight supply.

B. Charging stations. HQD's experimental Rate BR appears to be a sensible product: customer-specific blocked pricing using an hours-of-use tariff structure. A dynamic pricing alternative is to offer the owner a relatively stable customer and demand charge and then provide short-notice pricing.

Distributed Generation

HQD offers a net metering rate that is similar to many net metering rates in other jurisdictions. Their DG pricing faces the same challenges as those faced by other utilities: 1) recovery of distribution costs from customers under net metering of site usage; 2) determination of a commonly accepted definition of avoided costs as a basis for sales by customers to the grid; and 3) retail pricing to reflect avoided costs, however they are defined.

- Cost recovery requires improvement on net metering due to lack of sufficient data to determine a customer's responsibility for distribution costs.
- Industry stakeholders have widely varying views on avoided costs. Utilities accept avoided generation costs, narrowly defined, while DG advocates believe that there are substantial avoided transmission, distribution, and environmental costs, as well as other grid impacts. No early resolution is expected in this debate.
- Avoided generation costs vary with time, with variation specific to the utility. Blocked rates tend not to approximate avoided costs well while TOU rates are more accurate but more complex.

The review of DG pricing suggests that: 1) more detailed metering is essential for the determination of distribution cost responsibility; and 2) pricing will require agreement on avoided cost.

[1] A "two-part" design consists of 1) a base bill, with a standard tariff applied to contract quantities of energy and demand; and 2) an incremental energy charge, in which short-notice hourly energy prices are applied to departures of actual load from the contract quantity.

Storage capability complicates this picture somewhat, but does not change the conclusions. Storage permits the site generator to physically bank energy and use it at other times or sell it back to the grid at avoided cost.

Rates and Costs

HQD does what many utilities do in basing its revenue recovery on embedded cost but recognizing marginal cost in its ratemaking where possible. HQD's limited variability in marginal cost is reflected in its pricing, which is not highly seasonal or time-varying, but involves demand charge-related signals to customers regarding the cost of the 300 hours of winter peak when system reserves are at their lowest.

HQD's class revenue-to-cost ratios indicate the need for the utility to have greater flexibility than it has had available in the past decade. Moving these ratios in the general direction of rate parity would help to resolve some of the utility's pricing issues.

Summary

Appropriateness of HQD's Rate Designs. This review of HQD's tariffs, includes reference to design standards and industry practices. Most rates are similar in structure to other North American rates. Customer diversity requires the current range of rates. These rates, for the most part, are within industry standards of successful design and do not require further simplification. Rate options offer appropriate customization of rates to meet specific needs.

Emerging Challenges to Existing Designs. This rate review identifies instances in which changing circumstances may offer new rate design challenges.

- The proportional nature of HQD's past revenue increases appears to be accumulating problems of lack of rate parity that produce vulnerability to accusations of permitting or perpetuating cross subsidy. Cross subsidy appears to be raising Large Power customers' costs.
- Several particular challenges merit review in the future:
  - The net metering option may benefit from restructuring in advance of increases in participation to permit better measurement of customers' use of the distribution system.
  - The fixed cost recovery challenge of Domestic rates would benefit from further review, as minimum billing may not succeed in meeting ratemaking objectives of revenue recovery and price efficiency.
  - The structure of EDR and LRR pricing seems appropriate at present but might benefit from improvements in pricing efficiency via the two-part pricing model.
  - HQD offers interruptible service that is within industry standards and reliably delivers expected load relief. It might be useful to explore the use of market price-based curtailment programs to expand the range and scale of curtailable load that can be made available at times of low system reserves.

1. INTRODUCTION

Context

On July 11, 2016, the Régie de l'énergie (Régie) issued a public notice announcing its plan to review ways to improve the retail rate designs of electricity and natural gas in Québec.[2] The public notice stated an interest on the part of the Régie to ensure that rates in Québec follow industry best practices. In addition, the Régie drew attention to some issues of special interest:

- Rates for low-income households that facilitate timely bill payment.
- Rates that enable commercial and industrial customers to receive service at prices that are competitive with other North American jurisdictions.
- Rates that offer pricing solutions to industries with special needs.

Hydro-Québec Distribution (HQD) determined to obtain an objective, independent review of its retail rate designs to meet the objectives set forth in the public notice. The Company asked Christensen Associates Energy Consulting (CA Energy Consulting) to conduct this review. The review examines each of the rates of HQD's major classes of service—Domestic, Small, Medium, and Large Power—and a number of rate alternatives that play an important role in rounding out the retail product portfolio available to HQD customers.

In each case, the report examines commonalities and distinct properties of HQD tariffs relative to pricing principles and the practice of retail electric rate design in current use in North America. The review also focuses on the incentive properties of the rates, especially with respect to pricing efficiency, and pays attention to some current rate design issues common to most retail jurisdictions at present. These issues include:

- The recovery of fixed costs from mass market customers.
- Pricing for customers interested in distributed generation (DG).
- Pricing of standby generation services for business customers with site generation.
- Customer class segmentation and the use of industry-specific pricing.
- Pricing for customers with competitive alternatives.
- Management of cross subsidy and variations in allowed revenue-to-cost ratio across classes.

Organization of the Report

This report begins with a review of commonly accepted rate design principles and discusses special pricing considerations applicable to the HQD jurisdiction. Subsequent sections set out rate design information and issues by rate class. Section 3 provides a discussion of the Domestic class. Sections 4 and 5 review HQD's Power (business) rates, while Section 6 explores the issues surrounding a number of business rates that HQD (among other utilities) uses to extend the

[2] *Avis sur les Mesures Susceptibles d'Améliorer les Pratiques Tarifaires dans le Domaine de l'Électricité et du Gaz Naturel*, Régie de l'énergie, submitted July 11, 2016.

range of the retail portfolio to meet the diversity of retail customer needs. Section 7 reviews the issue of pricing of electric service for DG customers, setting out practices that avoid deterring or uneconomically pricing this service.

Each of the sections that conducts a review of the class or rates under discussion contains three parts. The first part describes HQD's current retail rate structures, including any proposed changes that are in the public domain. The second part provides a comparison of HQD's rate designs with current industry practice, noting any unusual design elements and the reasons for those elements. The third part explores current design issues, setting out possible design alternatives and their relative strengths.

Section 8 then investigates issues related to rates collectively. These issues include the cost underpinnings of pricing and the pricing flexibility that utilities need to possess in order to recover costs and meet common ratemaking objectives, including the avoidance of cross subsidization. Section 9 provides a summary of the ability of HQD's pricing portfolio to meet current and emerging pricing issues, and to satisfy the criteria of successful rate design.

2. RATE DESIGN PRINCIPLES

Criteria for Successful Rate Design

The generally accepted expression of objective criteria for sound rate design is found in the well-known text by James Bonbright that sets out a large number of criteria in three main groups.[3] A summary of that list follows.

Revenue-Related Criteria

1. Recover total revenue requirements.
2. Provide *revenue* stability and predictability.
3. Achieve *rate* stability for customers.

Cost-Related Criteria

4. Encourage efficient use of electricity.
5. Reflect present and future private and social costs and benefits of electricity service.
6. Strive for fairness in apportioning costs.
7. Avoid undue discrimination.
8. Encourage technical innovation and economic response in the production and use of energy.

Practical Criteria

9. Be simple, understandable, and acceptable to stakeholders.

[3] J.C. Bonbright, A.L. Danielson, and D.R. Kamerschen, *Principles of Public Utility Rates*, second edition, 1988, Public Utility Reports, Inc., pp. 382-384.

10. Be free from controversy as to interpretation.

Because the Bonbright criteria for sound rate design were developed during the era of full rate-of-return regulation of vertically integrated utilities, it may be tempting to consider that their appropriateness may have diminished over time. However, these criteria are partly an expression of the objectives of the operation of a competitive market, which regulation traditionally strives to emulate. Criteria 4, 5, and 8, combined with criterion 1, simply state that regulation should strive for a competitive market outcome subject to the constraint of revenue recovery at a competitive rate of return. Other criteria—2, 3, 6, and 7—outline the costing and pricing conditions that support the criteria of fairness and stability. Criteria 9 and 10 also support the effective functioning of a successful market by striving to clearly define the product and minimize the information cost of understanding the product.

Another possible criticism of the Bonbright criteria might be that they are applicable to the regulation of investor-owned utilities, but less so to publicly owned utilities, such as Canadian Crown corporations or American municipal or co-operative distribution utilities. However, these utilities are usually required to conduct costing and pricing to ensure cost coverage under the same criteria. Departure from these criteria in favor of alternative objectives can leave the utility and the regulator without sound criteria for decision-making.

In practice, even when regulators and utilities strive to meet the Bonbright criteria, they confront two issues. First, social issues impinge, of necessity, on utility decision-making. An American example is the introduction of renewable resource objectives by many American legislatures in the form of renewable portfolio standards, which obligated a jurisdiction's utilities to obtain a legislated minimum level of renewable energy production or purchases by a certain date. Second, even in the absence of political and social objectives, the Bonbright criteria involve tradeoffs because not all criteria can be simultaneously satisfied. For example, attaining revenue sufficiency (criterion 1) almost invariably implies compromise with pricing efficiency, as defined by the competitive market criterion that price equals marginal cost, where marginal cost is defined as the cost of providing the next unit of the good or service.

Even acknowledging such issues, it is still the case that the Bonbright principles, as the embodiment of the core regulatory objective of emulating the competitive market subject to revenue recovery, are still a satisfactory benchmark for sound rate design.

Circumstances Special to Hydro-Québec

Utilities preparing rate applications develop ratemaking objectives that reflect a mix of the criteria presented above, but typically taking into account circumstances specific to their utility or their regulatory jurisdiction. For example, in some United States jurisdictions there once was a requirement that domestic class customer charges must be zero. California's IOUs still practice this approach. It should be no surprise that HQD operates under circumstances that influence its rate and pricing objectives.

Two such circumstances are evident in HQD's past pricing approaches:

- The Domestic customer class has a low revenue-to-cost ratio compared to other jurisdictions. A low revenue-to-cost ratio is a common feature of rate design at many utilities. HQD's situation may be exacerbated by the fact that the utility's Domestic customers consume relatively large amounts of energy due to their longstanding high propensity to use electric space heating. Since electric power is likely to be a larger share of consumers' budgets in Québec than elsewhere, there may be greater constraints on covering cost due to the expected impact of price increases on low-income customers.
- Large Power customers have traditionally enjoyed overall low electricity prices when compared with other jurisdictions, both Canadian and American. However, retaining this objective is at odds with the desire to keep Domestic rates low. This challenge is not found as prominently in other North American jurisdictions despite the fact that almost all of them have higher generation costs than those paid by HQD.

While HQD may not have had strong external social requirements in the past, aside from those listed above, and perhaps including the requirement to acquire certain amounts of wind power, the regulatory picture is likely to change somewhat in the next few years. Québec's Ministry of Energy recently released an initiative that involves a range of requirements that will affect HQD rate levels and may affect rate structures as well. The document, *The 2030 Energy Policy: Energy in Québec, A Source of Growth*, stresses objectives of:

- Favoring a low-carbon economy.
- Optimally developing Québec's natural resources.
- Fostering responsible competition.
- Capitalizing on energy efficiency potential.
- Promoting the "entire technological and social innovation chain".[4]

These objectives do not impose direct, fixed obligations on HQD, but stress renewable energy and energy efficiency. This can be achieved in such a way as to move prices in the direction of price efficiency (marginal cost, including marginal environmental cost) or to move prices away from efficiency. Regardless, they present HQD with a challenge to make rates and pricing meet social objectives. Such challenges are common in the utility industry today.

Perhaps a more unusual challenge, specific to the Québec jurisdiction only, lies in the enabling legislation of the Régie. Chapter IV, Article 52.1 states that, "The Régie shall not modify the rates of a consumer class in order to alleviate the cross-subsidization between the rates applicable to classes of consumers." This article has apparently been the subject of ongoing interpretive debate, but its practical effect has been to restrict the outcome of rate applications to proportional increases in rates regardless of trends in cost to serve. Normally, utilities strive to reduce cross-subsidy over time, bringing revenue-to-cost ratios closer together over time. Regulators can accelerate, slow, or reverse such moves as they see fit. If the meaning of Article

[4] *The 2030 Energy Policy: Energy in Quebec, A Source of Growth*. Presentation-format document, c. 2016, Government of Québec. Objectives are stated in the introduction, but discussed throughout the report.

52.1 accurately reflects its application, then it likely produces the most rigid pricing restrictions in North America.

This does not mean that sustained below average ratios do not occur elsewhere for residential classes, but utilities and regulators that resist movement to “rate parity” face unceasing resistance from intervenors for other rate classes. While rate applications can result in proportional price increases on some occasions, the natural outcome of regular cost-of-service studies is a gradual change in cost allocation burden over time, and almost certainly differential changes in price increases across rate classes, as sought by utilities and intervenors, and as required by regulators. In brief, an inability to depart from proportional price increases is very likely to lead to increasing dispersion in revenue-to-cost ratios.

Portfolio Choice and Rate Simplicity

The public notice of the Régie also mentioned the desirability of simplification of the options available to customers.[5] The concept of simplification can be interpreted as having two dimensions. First, simplification may mean a limitation in the number of rate options that are available to the customer. Arguably, one may wish to offer customers some degree of choice, since customers are diverse in their preferences and end uses. However, portfolio diversity can produce customer uncertainty if options proliferate. Second, simplification may mean ensuring that, for any given retail pricing product option, the customer can readily understand its properties and evaluate its fitness for their particular circumstances.

Regarding product choice, traditional utilities have usually relied on a single “base” tariff for each rate class, especially for mass market (small customer) rate classes such as the residential and small general business classes. Many utilities, especially small utilities, still follow this practice. However, the advent of competition in many North American markets has produced a proliferation of rate designs in an effort to ensure retention or building of market share.

An example of this tendency can be found at TXU, a large retail energy provider operating in the Texas competitive retail market. TXU offers nine different retail energy programs to residential customers.[6] These programs provide a diverse range of price firmness, contract duration (month-to-month, then 6, 12, or 24 months) and “greenness” of energy.[7] Their “featured plan” is a 24-month contract offering “free nights” (zero energy charge from 8:00 pm to 5:00 am) offset by relatively expensive electricity in other hours. The most flexible pricing is found in their MarketEdge[SM] plan, in which monthly energy price is indexed to natural gas prices.

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[5] The original French, from paragraph one of the public notice, is, “…une simplification des options offertes aux clients.”

[6] The customer learns of their rate options by specifying their zip code on the TXU website. This review used a Houston zip code, 77048, chosen at random, for illustrative purposes.

[7] https://www.txu.com/en/view-plans.aspx?customerclassification=residential&cint=5&dwel=01&prom=PS&zip=77048&tdsp=ER_CENTERP

This example illustrates that the competitive retail market can generate pricing and product strategies that offer even the least sophisticated customers significant product diversity in several dimensions.

The second dimension of simplicity, individual product structure, produces an immediate trade-off between pricing accuracy (relative to hourly wholesale prices) and complexity. As the rate designer progresses from flat to seasonal to blocked or time-of-use (TOU) pricing, and then to dynamic pricing products like critical-peak pricing and real-time pricing, prices increase in number and the pricing pattern becomes more complex. A seasonal TOU price can easily have three different pricing periods in each of three seasons. Thus, while product simplicity, one of Bonbright's criteria, is desirable, the rate designer is still confronted with attempting to determine the degree of complexity that each customer class is willing to accept.

Interestingly, the TXU rates feature relatively few prices for each of their products. In fact, all nine products feature a non-seasonal, three-block declining block tariff, with kWh boundaries at 500, 1,000, and 2,000 kWh. Clearly, this retail energy provider has chosen a strategy of product diversity combined with individual product simplicity for its residential customers. However, this is just one possible strategy, of course. Note, also, that the Texas residential customer receives two bills, one from the retail energy provider, and one from the delivery utility, which charges for distribution services.

In summary, the objective of rate simplification can be elusive, and the concept of effective customer service appears to allow for rate diversity within each class and a trade-off between price efficiency and rate complexity. This suggests that an electric power distributor should be permitted to maintain broad latitude in development of rate diversity and pricing plans.

3. DOMESTIC CLASS RATE DESIGNS

Current and Proposed Rates

HQD currently offers Domestic customers service predominantly under its Rate D. Customers with dual-fuel capability for water and space heating have access to another tariff, Rate DT, tailored to their needs. However, the Company is also advancing a set of proposed tariff structure changes that, beginning April 1, 2017, subject to regulatory approval, will alter the conditions of service measurably. This review will consider current and proposed structures.

Current Rates. Most Domestic customers are served currently under Rate D. This rate's structure consists of customer and energy charges for customers less than 50 kW of peak demand, and a seasonal demand charge for customers in excess of this amount.[8]

[8] The demand charge is seasonal at present. The summer demand charge was introduced recently, and is intended to rise to the winter demand price level over time.

The structure of Rate D has the following characteristics:

- A daily customer charge.
- A non-seasonal inclining block energy charge, whose single block boundary is set at 30 kWh/day (which amounts to 900 kWh in a 30-day month).
- A demand charge for customers whose peak demand exceeds 50 kW. The billing demand in each month is based on a 65% ratchet value set by the highest peak demand in the past year's winter months.

Rate D serves a broad range of customers: single-family homes, apartment buildings, community residences and rooming houses, bed and breakfast establishments and farms; all within definitions specified by the tariff.[9] The blocked energy charge structure reflects the presence of space heating customers who are costlier to serve in peak periods dominated by space heating load than in other hours. Non-space heating load is presumed to produce consumption totals below the first block boundary of 900 kWh, with the result that space heating is charged mostly at the second tier price.

HQD offers service to dual-energy customers under Rate DT. Customers who can use a fuel source for space heating and water heating are eligible for this rate. The rate's prominent feature is a company-provided outdoor temperature gauge that controls system use. Below -12°C (or -15°C, depending on the weather region) the alternative fuel supplies energy for heating. Otherwise electric heat is used. Customers can override the switch and use electric heat in cold weather, but pay a high premium price (currently $0.2691/kWh). The rate acts as a weather-based demand response rate, except that the weather signal automatically curtails usage, causing a change in energy source to a less expensive alternative. Note that the high price applies to all site consumption during cold weather, encouraging energy conservation generally. The rate's energy price for warmer weather is reduced from that of Rate D due to the avoidance of the need to generate energy in high-cost hours.

An additional rate, Rate DM, is closed to new customers but still serves customers eligible for the rate before May 31, 2009. This rate tries to emulate Rate D, adding a multiplier to adjust customer, energy, and demand charges for the number of dwellings or rooms associated with accounts other than single-family dwellings.

Thus, HQD's current Domestic class rates do not offer customers broad choice but do provide customized pricing for customers who are measurably different from the mass of Domestic customers.

[9] Farms are identified explicitly in the HQD tariff sheets, an approach that is not always followed by other utilities. HQD conducts an annual rate comparison survey of twenty-five Canadian and American utilities, including HQD. We reviewed the tariff books of seventeen utilities and found nine with explicit references to farms. Only one utility has a rate for farms other than an irrigation rate, of which there were just three. Of the nine tariff books that mention farms, most include farms in the residential class, but in one case, NB Power, farms are assigned to class based on size. One utility, Northern States Power, had a farm rate until 1988, but then terminated the rate and moved these customers into its residential class.

HQD's Proposed Domestic Rate Changes. HQD has proposed changes to Domestic class rates in a recent tariff strategy document that are intended to unfold over a nine-year period. When completed, subject to regulatory approval, Rate D will be applicable to customers with demand less than 65 kW and:

- Will have eliminated its customer charge and replaced it with a minimum bill provision.
- Will maintain a two-tier inclining block structure.
- Will increase the 1st tier threshold from 30 kWh to 40 kWh per day.
- Will recover revenue shortfalls by increasing energy tier prices to supplement the general rate increase.

Additionally, the Company has obtained general approval to segment the Domestic class on the basis of size. Customers with peak demand in excess of 50 kW will be offered service under a new tariff, Rate DP, which will have a demand charge structured in the same manner as that of the current Medium Power Rate M. The new Rate DP, as proposed, will also feature a two-tier inclining block structure, but its block boundary will be significantly higher than that of Rate D, being set at 12,600 kWh, which is the minimum demand of 50 kW multiplied by an expected subclass load factor of 35%. Customers who are eligible for both Rates D and DP will be billed on their chosen rate unless the alternative rate results in a bill 3% lower than their chosen rate, in which case they will be moved to the less costly rate.

HQD Designs and Industry Practice

HQD's current Domestic class rate designs are quite similar to others in the industry in that they feature a single dominant rate with customizing provisions to manage special needs. The inclining block structure can be found in numerous utilities as well, although in the United States the purpose of the structure is to provide an elevated energy price for high summer usage due to air conditioning in high-cost hours.

Demand charges are not widely found in residential tariffs elsewhere, partly due to the classification by other utilities of larger customers such as farms under small general service tariffs. However, the issues of fixed cost recovery and distributed generation pricing are increasing interest in the use of residential demand charges, in some cases for the entire class.[10]

HQD plans to offer the dominant Rate D, and the proposed Rate DP for larger customers, along with (demand response) rate DT for fuel switching customers. However, in contrast to other utilities, HQD does not offer some options found commonly in other jurisdictions, such as TOU with peak periods and prices announced in tariff sheets. Many utilities offer time-of-use options to residential customers, often under regulatory mandate, to induce customers to shift usage to relatively low-cost time periods and away from high-cost periods. However, these rates typically have very low participation, due to issues of recovery of the extra metering and billing costs associated with TOU service.

[10] Distributed generation pricing is discussed in Section 7, below.

HQD has not been a strong candidate for TOU service because of its unusual marginal costs, which are smoothed over time by the dominance of hydro-electric power. HQD's demand management challenge is to find ways to obtain demand reductions in the few hours per year when the system is supply-constrained. A TOU or demand response rate based on temperature or some other indicator of system reserves that provides a signal in these few hours is valuable, but a TOU design, even a seasonal design for winter only, may not necessarily be cost effective. However, if integration with the rest of the North American grid increases, due perhaps to the reduction of transmission constraints over time, and marginal cost patterns begin to look similar to those of other utilities or regions, opportunities to use time-varying pricing at HQD might increase.

This project conducted a brief review of residential rates in Canada and the United States. The review revealed that while many utilities offer non-seasonal pricing with flat energy charges, several examples of seasonal pricing can be found. The review investigated the rates of 25 utilities, 11 in Canada, including HQD, and 14 in the United States. Collectively they offer 69 rates or price alternatives. (However, this overstates diversity, since the alternatives often reflect customer diversity rather than the presence of customer choice. This is particularly true in Canada, where the alternatives include differentiation of charges by customer type (single- or three-phase; or amp size of service; or urban/rural/seasonal status).

Customer charges are common and demand charges are rare. Customer charges are mostly monthly in form, but nine rates/alternatives, including HQD's four planned rates are daily. Epcor in Alberta, Seattle City Light, and Central Vermont Public Service have daily customer charges as well. The review found just one utility, Pacific Gas & Electric, in California that has no customer charge.

Utilities frequently list a minimum bill provision. Predominantly it consists of the customer charge. For one utility, Pacific Power of Oregon, the minimum bill appears to be unbundled, consisting of a customer charge that is a combination of a Basic Distribution Charge of US$9.50/month and a "Minimum Demand Charge" of US$3.80/month. The demand label is simply identifying the demand-related cost causation of that component.

Energy charges are predominantly non-seasonal, but 26 of 69 rates/alternatives, or about one-third, have seasonal components. Of the seasonal energy charges, 11 have a TOU component and 6 are blocked. In contrast, of the 43 non-seasonal rates, only two have TOU pricing and just 9 have pricing blocks. The apparent conclusion is that as seasonal detail increases, utility willingness to price at least the peak season with TOU or blocked pricing increases as well.

Additionally, the review uncovered seven cases of demand charge pricing, of which one is at HQD (counting the proposed DP tariff). All other demand charge rates are found in the United States. These appear mostly to be related to optional tariffs that may not feature significant participation.

Dual-system pricing appears to be quite rare. However, the concept of short-notice pricing based on system conditions, as approximated by Rate DT, has an emerging counterpart in demand-response products offered to residential customers in some jurisdictions. Rate DT's "short notice" is actually zero formal notice: when the outside temperature reaches the benchmark temperature, an automated switch converts from one fuel source to the other. However, customers can anticipate the conversion, and the high pricing of very cold days by acquiring information about the local temperature, a relatively easy task. True "short-notice" pricing products used by residential customers include critical-peak pricing (CPP), peak-time rebate (PTR) (a variant of CPP) or, in rare cases, real-time pricing (RTP). Other utilities have used demand-response products to enhance the value of their TOU programs. HQD has found a technical alternative to such products in which air temperature serves as a proxy for system marginal cost.

An interesting jurisdiction for review of residential rates is that of OGE Energy (Oklahoma Gas & Electric) whose peak season is summer.[11] They offer five residential tariffs:

- Residential (R-1): three seasons; 2-tier inclining block in summer, 2-tier declining block in winter; flat shoulder season.
- Residential TOU (R-TOU): two seasons: winter as in R-1; 5 summer months—TOU.
- Residential Guaranteed Flat Bill (R-GFB): a fixed dollar amount for a one-year contract, regardless of usage level.
- Residential Variable Peak Pricing (R-VPP): two seasons: winter as in R-1; 5 summer months—4 short-notice levels of energy price for five afternoon hours on the next day.
- Residential Time-of-Use with CPP (RT-CPP): two seasons: winter as in R-1; 5 summer months TOU but with short-notice critical-peak price of $0.43/kWh.

This portfolio is interesting for two reasons. First, the utility has chosen to offer a fairly broad spectrum of tariff options to residential customers. In addition to a basic tariff, there are three TOU-based rates, two of them with short-notice pricing dimensions that solicit demand response and reward customers for load shifting at high-cost times. The other tariff is at the opposite end of the pricing spectrum, offering a fixed bill amount guaranteed not to change for a full year. (However, the customer's fixed bill offer for the next year depends on the current year's consumption, weather normalized, imposing an implicit charge for increasing usage.) Second, the TOU pricing strategy is seasonal. Off-peak seasons have flat or blocked pricing that is simpler than TOU pricing.

TOU Pricing. This portfolio raises the issue about the desirability of TOU pricing for mass market customers. Many United States utilities offer TOU tariffs to residential customers but participation is typically quite low. Historically, TOU pricing for this class has faced several challenges in gaining acceptance. For utilities lacking in adequate metering, data recording, and billing capabilities, introducing TOU service for mass market customers can be costly. Thus, there is a tradeoff between increased cost to serve and the value of price response that can deter investment by the utility and participation by customers, especially if the additional

[11] To be specific, the focus is on their Oklahoma jurisdiction.

program costs are assigned to TOU customers. (OGE Energy is an exception, having invested in widespread interval data recording.)[12]

Additionally, wholesale market prices have, for some time, featured not very sharp peak:off-peak price ratios, often in the range of 2:1, perhaps reflecting the presence of ample capacity in most hours. Retail pricing based on such ratios create limited opportunities for bill reductions by customers, further limiting participation.

It is worth noting that HQD undertook a voluntary TOU/CPP pilot program several years ago. While recording price response in a manner similar to other pilot programs, the study also found tendencies for response to weaken when CPP events were called on consecutive days due to a period of sustained cold weather.[13]

Despite these challenges, some jurisdictions, notably California, have pursued TOU pricing. California plans to require that utilities under its jurisdiction offer default TOU rates with opt-out provisions to residential customers. Pilot programs are under way now and a policy resolution is expected in 2019. Other jurisdictions are not immediately imitating California.[14]

Green Pricing. Other jurisdictions also offer green power pricing, which usually consists of a rider that charges a premium on the energy charge and sometimes an extra administrative fee (customer charge) for the utility to secure renewable energy. In the case of HQD, in which virtually all energy supplied is hydro-electric or wind power, there has been no value in making such an offer. A possible future use might be to sell renewable energy in the form of solar or wind energy to customers, with a premium charge helping to recover revenue for these new energy forms, whose costs tend to be above the market price, and whose energy is non-dispatchable. However, at present, the costs of HQD's renewable energy purchases are simply incorporated in its weighted energy purchase pricing.

Rate Design Issues and Approaches

Fixed Cost Recovery. HQD's current and proposed rate designs are confronting perhaps the primary rate design issue being faced by North American utilities at present: recovery of fixed costs. Residential rates have traditionally recovered fixed costs only partly via fixed charges per customer-month. Volumetric charges have recovered the remainder, typically via an energy

[12] As well, utility rates policies have sometimes attempted to recover from TOU rate participants the revenue attrition that naturally arises from offering customers a choice in rates. TOU rate volunteers typically have low on-peak load shares relative to the class, and thus lower TOU bills than standard tariff bills. Thus, they cost somewhat less to serve than the average customer in the class, and can be charged a lower rate in consequence. Revenue neutral pricing of TOU customers not only defeats participation but likely overcharges them.

[13] *Projet Tarifaire Heure Juste*, Séance de travail du 16 septembre 2010, Dossier R-3740-2010.

[14] The Legislative Counsel's Digest of California AB 327, passed Oct. 7, 2013, states that the bill "permits the California Energy Commission to "authorize an electrical corporation to offer residential customers the option of receiving service pursuant to time-variant pricing and to participate in other demand response programs. The bill would provide that a residential customer would have the option to not receive service pursuant to time-variant pricing and not incur any additional charge as a result of the exercise of that option." (pdf acquired at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201320140AB327.)

charge due to the complexity and cost of demand pricing for mass market customers. This widespread departure from pricing based on cost causation arises from the general desire of utilities and regulators to avoid burdening low-usage customers' bills with high average cost per kWh. Since low usage is believed to be closely correlated with low income, retaining low customer charges was thought to be essential to delivery of broadly available residential service.

This problem has traditionally been masked by steady growth in sales. However, with slowing sales growth since the Great Recession, and particularly with sales outcomes below sales forecasts, under-recovery of fixed costs has resulted. This problem has been compounded by the emergence of distributed generation (DG) among residential customers, chiefly with the installation of solar panels. In the United States, net metering has been the dominant form of contracting with DG customers. The outcome has been dramatic reductions in fixed cost recovery from DG customers, since volumetric fixed cost recovery has been based on net sales rather than gross consumption of the customer site. (Issues of DG pricing are discussed in Section 7.)

One approach to this issue is simply to apply a "straight-fixed-variable" (SFV) approach to cost recovery and significantly increase customer charges to cover fixed costs. At the same time, the utility reduces the energy charge to return to the original level of revenue recovery. However, this approach exacerbates the problem of electricity cost for non-DG low-usage customers. A utility can ease the transition in rates by modifying prices through multiple rate cases, or by finding some alternative means of identifying low-income customers.[15]

Some utilities attempt to identify low-income customers directly rather than via their customer billing data, and provide them with a bill discount in some form regardless of their rate structure. For example, California utilities have a provision in their residential tariffs that allows customers who qualify for low-income assistance to obtain a bill discount.[16]

A second approach is to use graduated customer charges. In this case customers are divided into three or more tiers based on average historical billing. Customer charges for the largest customers are designed to fully cover fixed cost while charges for smaller customer cover reduced percentages of cost. The customer's tier status is adjusted once per year. This approach achieves improved cost recovery while retaining low customer charges for low-usage

[15] For utilities that favor SFV, or perhaps any utility interested in fixed cost recovery, an issue not discussed here is whether fixed costs are readily identifiable. In distribution, a traditional costing issue is determining the proportions of costs that are customer-driven versus demand-driven. In the case of tariffs that lack a demand charge, the issue is what share of demand-driven costs ought to be recovered by a customer charge and what share ought to be recovered in the energy charge. A recent article by offers a relatively simple statistical method to estimate these shares. L. Blank and D. Gegax, "An Enhanced Two-Part Tariff Methodology when Demand Charges are not Used," *Electricity Journal*, 29 (2016) pp. 42-47.

[16] The Pacific Gas & Electric website lists criteria for CARE eligibility. They include income per household thresholds, that vary with number of persons, plus persons living in certain types of housing. Source: https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/longer-term-assistance/care/care.page?WT.mc_id=Vanity_care.

customers. The difficulties with the approach are rate complexity, potentially significant change in customer bills for customers at the tier boundaries, and poor correlation between customer size and income level.

A third approach, adopted by HQD, is to substitute or supplement customer charges with minimum bills. In fact, as noted above, some utilities have a minimum bill provision that sets the minimum bill equal to the customer charge. More generally, a minimum bill is designed to catch a predetermined range of relatively low-usage customers with an obligation to contribute to fixed costs. In HQD's case, the Company proposes to combine this feature with an increased tier 2 energy charge.[17] This appears to achieve partial fixed cost recovery through an increased fixed charge while retaining some fixed cost recovery in the tier 2 energy charge.

One difficulty with a minimum bill approach is its price signaling effect for low-usage customers. For a certain range of usage expansion, the marginal price is zero, which is well below marginal cost. Since DG customers often fall into the low-usage group, the question arises whether a minimum bill will adequately recover fixed costs. DG advocates argue that fixed costs are, in fact, quite low, and that the minimum bill approach is desirable. Other stakeholders, along with utilities, do not accept this view of fixed costs, and thus find minimum billing to be an inadequate approach to DG customer pricing. If rates for DG and standard tariff customers are linked, then the minimum billing approach may not be desirable. If HQD has not studied minimum billing in light of DG service, then this approach might deserve review.

A fourth approach is to introduce demand charges broadly among residential customers. The extra dimension of price information—load factor—offers the opportunity to improve accuracy in cost recovery across customers. Customers with high load factors receive bills lower than those of customers with comparable usage totals but with low load factor. The costs of meter updating, data management, billing upgrades, and customer education appear to be challenges to the cost effectiveness of this strategy, but it is currently under discussion especially among utilities in the United States that have already invested in smart metering and data system upgrades. One additional challenge to this approach, though, is that it will not necessarily protect low-usage customers from bill increases. While costs will have been more accurately allocated than previously, a low-usage customer with below-average load factor will still experience a significant bill increase.

Beyond rate structure changes, some utilities have experimented with departures from traditional rate-of-return regulation by adding decoupling provisions. Under decoupling, the utility keeps a balancing account of fixed cost recovery and uses a tracking mechanism to add or subtract an energy-only charge to customer bills, in the same manner as a fuel cost recovery charge. This approach has a number of challenges. It ensures fixed cost recovery for the utility but can impose unexpected bill increases and bill variability on customers. The approach also distorts prices, perhaps away from marginal cost, thereby reducing the effectiveness of the

[17] For the planned transition period, the tier 2 energy price is planned to increase at twice the rate of the tier 1 price, subject to a provision that customer bills not increase by more than 3% more than the average bill. For 2017, both prices are proposed to increase proportionately.

price signal to customers. Most importantly, perhaps, it fails to resolve the challenge of base tariff prices failing to reflect cost causation.

As might be expected, there is no best solution to the issue of fixed cost recovery from residential customers, given the constraint that low-income customers will require subsidization. HQD has some company among utilities that are interested in the use of minimum bills. No dominant approach is being adopted by the industry and each approach has challenges. This gives utilities struggling with this challenge fairly broad latitude in the pursuit of solutions.

Pricing Space Heating. A number of North American utilities provide separate tariffs or provisions in their standard residential tariff for the treatment of space heating. Interestingly, most Canadian utilities do not have special provisions, perhaps due to the ubiquitous nature of space heating in Canadian jurisdictions. Blocked tariffs are an indicator of recognition of this need. Other forms of pricing are also used in pricing these loads. They are predominantly time-varying: seasonal and TOU variants that permit charging a higher energy price in peak hours that typically coincide closely with the intense use of heating and cooling. However, each involves an increase in price complexity and, in the case of TOU pricing, support costs such as metering and billing. HQD's approach—blocked pricing—is conventional and widely accepted in the industry for both space heating and cooling.

Some utilities have adopted TOU designs but included demand response concepts (CPP or PTR) in search of enhanced response when it is particularly valuable. This even more complex approach requires additional metering, communication, and billing capabilities. However, some utilities believe that they would prefer to offer a residential TOU option only if they are allowed to offer a demand-response option as part of the package.

Dual-Fuel Pricing. In HQD's case, the DT tariff also prices heating (and water heating), in this case for dual-fuel accounts. As mentioned above, the DT structure is similar to the concept of demand-response pricing and represents an improvement in pricing of energy services over a simple blocked design.

If HQD places high value on restraining space heating consumption at times of high marginal cost, it is possible to extend the Rate DT concept to Rate D. In fact, HQD is proposing to undertake a direct load control pilot program to explore customer willingness to switch fuel source at times of low system reserves. In exchange for permitting heating curtailment, the customer will receive a bill reduction for kWh curtailed.[18] This approach has parallels in the heating season in the United States. For example, Xcel Energy's Minnesota service territory offers a "Savers Switch" program for this purpose.

A price-based approach that offers customers somewhat greater control of their heating system might be developed by adding a demand response provision like CPP with automated thermostat control. California has performed experiments of this nature and may offer

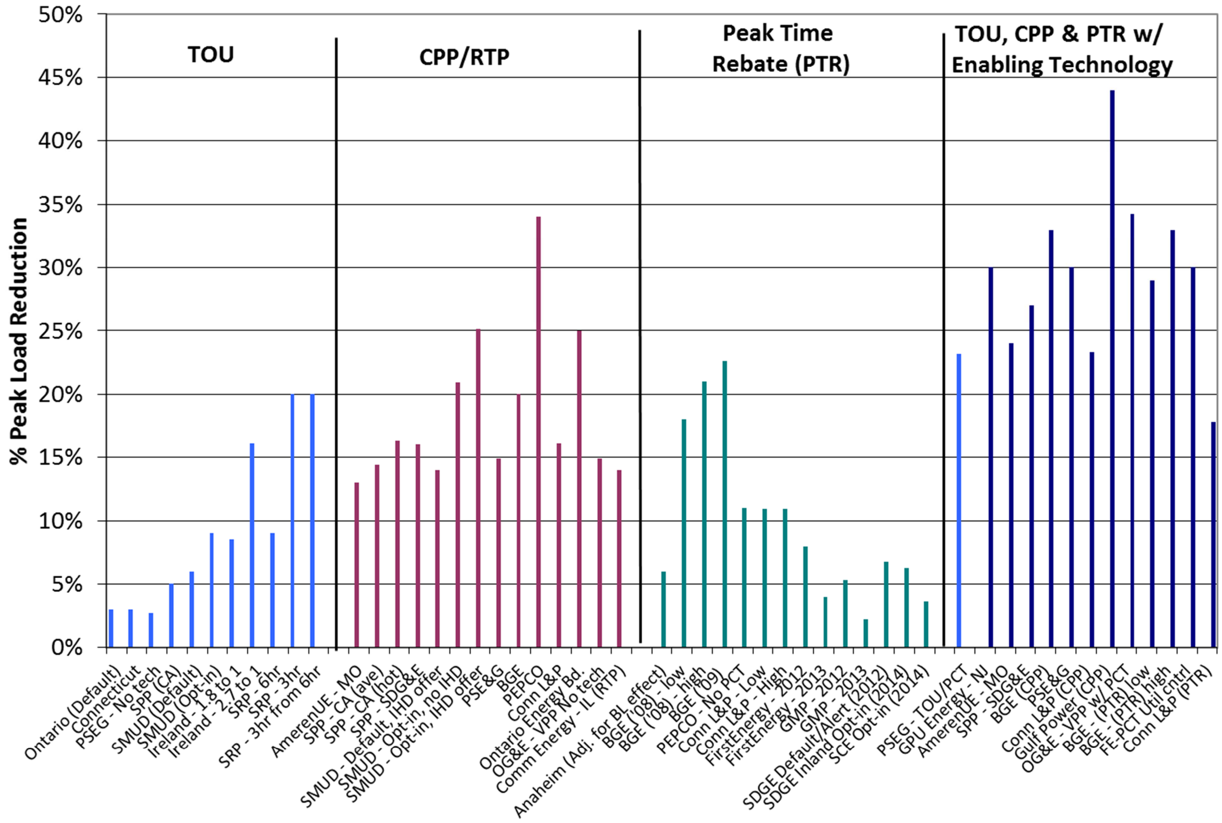
[18] The value of the compensation has not yet been determined.

instructive information about impacts and potential. Experiments in North America with demand response programs have yielded a wide range of results. Dynamic pricing programs appear to outperform static TOU programs in terms of peak load reduction, and dynamic pricing programs with technology assistance do even better.

A cautionary note is worth mentioning here: heating and cooling systems have technical limitations that extreme weather can reveal. For example, in southern United States jurisdictions a period of persistent excessive heat can render price-based heating through automated thermostats ineffective because the system works continuously to maintain an elevated room temperature programmed by the customer. Similar problems might emerge in Québec on extremely cold days due to the heating system needing to work continuously to maintain even a reduced temperature in the home. An additional complication will arise if the heating system is not centrally controlled but instead controlled in each individual room. In summary, price-based programs may offer load management and cost control benefits, but their overall impacts needs to be studied.

Figure 1, below, summarizes the results of many studies, each with its own target customer group and pricing. Most have a focus on summer peaking and the extent of possible impacts on heating systems is not as well documented. The three left-hand panels report results for dynamic pricing programs without the use of technology to enhance customer response. The right-hand panel reports the impact of introducing technology response, such as programmable thermostats linked to price signals.

Figure 1
Percentage Reductions in Peak Load in Dynamic Pricing Programs



Source: presentation by S.D. Braithwait, *Efficient Electric Rates: Design and Customer Response*, EEI Advanced Rate Course, July 2016.

Small Customer Bill Payment Capability. The ability of customers to pay bills is primarily an issue of overall level of bills relative to customers' ability to pay. HQD has studied the trend in prices and incomes of its customers over time and is familiar with the challenge posed by increasing costs. This issue quickly becomes a discussion of cross subsidy, which is discussed later. However, it may be worth mentioning that utilities have undertaken limited investigations of rate design changes to reduce the consequences of bill payment problems.

Utilities have developed "lifeline" rates that reduce costs to customers based on income. An illustrative program can be found at Central Maine Power. Customers are eligible for Lifeline service if they are eligible for the Home Energy Assistance Program (HEAP), live in subsidized housing or have special medical needs. In their case, acceptance depends on annual income and past energy use. The result is a lump-sum bill credit.[19]

An associated legal provision in some jurisdictions is a rule against disconnection of heating-related service during cold months. For example, the State of Wisconsin prohibits disconnection

[19] See their reference at: http://www.cmpco.com/YourAccount/payyourbill/ServiceAndAssistance.html.

of heating utilities from November 1 to April 15. Customers must make up late payments outside the heating season to avoid future disconnection.[20]

Additionally, utility costs of disconnection and reconnection can be reduced by means of prepayment rates, which have been tried in selected jurisdictions. For example, several retail energy providers in Texas offer this service.[21] Under such rates, customers deposit funds at times when their account balance approaches zero, supposedly inducing more responsible consumption and greater interest in energy efficiency measures for the longer term, while reducing utility costs. The reduced utility risk serves as a vehicle for reducing the bill slightly. However, such measures do not alter the central problem of overall increase in cost relative to ability to pay.

The foregoing discussion of bill payment and disconnection raises the more general question of rate design that acknowledges low-income customers. In theory, utilities are not obligated by the regulatory compact to provide subsidies to low-income customers. Arguably, these are the responsibility of governments. However, there is lengthy history of utilities providing bill discounts in exchange for the right to collect the revenue shortfall from other customers. As noted above, the use of customer charges that under-recover customer-related costs is very common. This approach is recognized as a poorly targeted mechanism in that many low-income customers live in large families in housing units with large consumption, or in poorly insulated/low quality housing that has high heating and cooling bills.

Approaches that make use of customer billing data only in awarding discounts are likely to be less useful that methods that identify customers directly by means of some indicator of income. Naturally, these are not perfect, since they rely on measures of eligibility that may change or not be as accurate as desired. Additionally, eligibility rules can be subject to abuse. Nevertheless, it is worthwhile for a utility to consider such explicit alternatives, since a targeted approach permits reduction of widespread subsidy of broad segments of the residential class in an effort to ensure the “affordability” of energy for heating.

4. SMALL AND MEDIUM POWER CLASS RATE DESIGNS

Current HQD Rates

HQD offers a single base tariff to each of its Small and Medium Power classes, Rates G and M respectively, and includes some special provisions for unusual circumstances. An additional tariff, Rate G-9, offers service to low load factor customers, and supports independent power producers with backup service. Rate G serves customers up to 65 kW of minimum billing demand, whereas rate M serves customers above 50 kW. As with Domestic customers, a customer charge and demand charge apply in Rate G when peak demand exceeds 50 kW.

[20] Statutory text is at: https://docs.legis.wisconsin.gov/code/admin_code/psc/113/III/0304.
[21] For reference, the Texas Public Utilities Commission offers a frequently asked questions website: https://www.puc.texas.gov/consumer/facts/faq/Prepaid.aspx.

Rates G and M both have a non-seasonal declining block energy charge and, above 50 kW, a demand charge whose billing demand includes a 65% ratchet based on maximum winter demand over the past year.[22] The declining block structure, combined with the current demand charge for Rate G of $17.31/kW, act to reward high load factor customers with reduced average price per kWh. Small Power customers on Rate G below 50 kW appear to enjoy a significant price discount relative to customers larger than 50 kW. However, HQD is increasing the second tier price faster than the first tier price, in order to eliminate the declining price structure, a plan accepted by the Régie. Larger customers, who pay more on average than smaller customers, benefit from converting to Rate M, leaving Rate G as a non-demand rate for small business customers. Low load factor customers tend to migrate to rate G9 at the 65 kW level.

Rate G-9 provides service under a low demand charge relative to that of Rate M and an offsetting high energy charge to ensure revenue recovery. The demand charge includes a 75% ratchet on the maximum demand of a winter month within the past 12 billing periods. This rate allows customers with periodic high demands to contribute to fixed cost recovery without paying a high average overall price. The rate is not intended for standby service as it excludes independent power producers.

Rates G, M, and G-9 offer a “short-term contract” option that excuses customers from the ratcheted peak demand, but for which a premium demand price applies in winter periods as well as an increased customer charge.[23]

HQD also offers an array of rate options to meet special needs. These options include, in the order presented in the tariff book: 1) transitional rates for photosynthesis;[24] 2) a rate provision to permit the “running-in” or setup of new equipment, and a second alternative provision for equipment testing; 3) interruptible pricing; 4) the “Additional Electricity Option”; and 5) an economic development rate (EDR). The photosynthesis rate concept is being reviewed in another report commissioned by HQD. The concept of industry-specific pricing will be reviewed below in Section 5. Interruptible pricing and EDRs will be discussed in Section 6, below.

HQD’s “running-in” rate provision is available under Rate M and is available to customers who wish to introduce new equipment without having concerns about ratcheted demand producing extra costs for a full year following a billing month with unusually high demands. The utility bills customers for periods of equipment testing on the basis of past average price of usage under normal billing conditions, with a bill premium of 4%. This rate permits use of this option for a short period only—six months for customers with more than a year of prior service and 12 months for less than a year of prior service—and only by prior application.

[22] HQD plans to gradually remove the Rate G declining block over time.

[23] Rate G also includes a “winter activities” provision for customers eligible before April 30, 1988 that offers special seasonal pricing. Customers served under this provision face the short-term contract prices, and the rates escalate at 2% per year.

[24] Note that this rate, by its nature, provides a transition between the old tariff and the base rates and therefore is closed to new subscribers.

The alternative equipment testing provision is available to both Rate M and G-9 customers but is available for just one to three months. In practice, the equipment testing option is used for smaller-scale equipment, while the "running-in" option applies to whole processes or new plants, which usually takes longer that the testing envisioned for the equipment testing provision. This provision also requires advance notice to HQD. In this case, the customer is again excused long-lasting peak demand impacts and pays an average price based on past usage patterns established in the preceding 12 months. However, the customer is deterred from exceeding the past usage level per billing period of that previous 12 months, by being required to pay for incremental usage at a premium price, currently $0.10/kWh. This provision also permits the utility to restrict testing at short notice under conditions of reduced system reserves.

The Additional Electricity Option offers customers an opportunity to purchase electricity at a blend of Heritage Pool prices and market-based prices, as represented by HQD's avoided cost as calculated one week in advance of the date of retail sale. The weighting of market-based prices is based on the number of hours in the service period during which HQD makes short-term purchases. By prior arrangement customers can acquire short-term limited access to electricity. The amount that can be purchased in each 15-minute period is the difference between the customer's real power demand in the current billing period and the "reference power" (the average of billing demands in the preceding three billing periods).

The Additional Electricity Option price is based on HQD's short-term marginal costs. In the past, that opportunity cost was derived from the energy prices from appropriate reference markets (usually the New York day-ahead market). However, the energy surplus facing HQD has caused the utility to derive the price from the price of Heritage Pool electricity. Since HQD wants to limit the risk of attempts to convert sales at Rate M to the Additional Electricity Option, the short-term marginal cost is constrained by a floor price based on the second-tier energy price at Rate M for 25-kV service and a 100% load factor ($0.055/kWh). The same applies for the Large Power customer option but, in that case, the floor price is based on the average price under Rate L for 120 kV and 100 % load factor ($0.0465/kWh). Since the price of Heritage Pool electricity is lower than the floor price, it is the floor price that is applied.

HQD Designs and Industry Practice

Most utilities follow the practice similar to HQD of introducing demand charges at some point for their business customers. Additionally, most small commercial tariffs tend to be simple in pricing structure, with limited time variation, either seasonal or by time of day. Declining blocks are sometimes used to reduce energy charges for customers who gain the size necessary to pay demand charges. Fixed, or demand-related, cost recovery shifts from the energy charge to the demand charge at these points.

Utilities typically do not provide reduced pricing for small commercial customers unless cost differentials justify such action. Additionally, base tariff designs tend to be simple, due to a combination of utility attitudes about customers' energy awareness and the relatively low energy intensity of many small businesses.

HQD surveyed a number of utilities regarding general tariff structures. The survey found 28 tariffs that are reasonably defined as "small general service" with peak demand values of less than 100 kW. These rate designs were predominantly declining block (12) and flat (7) with small numbers of seasonal and TOU provisions. Ten of these rates had a demand charge, most with a simple structure and no ratchet. Canadian utilities' rates showed a higher tendency to include demand charges, but this may be due to the tendency of United States utilities to segment general service customers to a greater degree than Canadian utilities. For the utilities reviewed, the range of peak demand at which customers become eligible for/required to use demand metering is 5 kW to 50 kW (or kVA, in one case), with most in the 20-50 kW range. HQD's proposed rates plan to use a 50 kW minimum, which is at the upper end of the range for group of tariffs reviewed, but not outside that range.

One does not find many utilities with "running-in" or equipment testing provisions, perhaps due to the less highly ratcheted demands found elsewhere. One example, applicable to large customers, occurs at NB Power in New Brunswick. Their Large Industrial rate schedule contains a "start-up" rate provision that applies for up to six billing periods. The load associated with the start-up must be interruptible with 10-minute notice. (This provision is not an economic development rate, because the Large Industrial rate also includes a "declining discount firm" rate provision that features a demand charge discount that reduces the demand price at a rate that declines over a five-year period.) Other utilities provide informally for exceptional circumstances, based on system capacity being available.

Several utilities also offer small business customers tariff options, including TOU pricing and green pricing. Portland General Electric's (PGE's) Small Nonresidential Standard Service tariff provides an illustration of tariff design with unbundled and renewable pricing in mind. This non-demand tariff serves customers below 30 kW of peak demand. The rate prices transmission and distribution services separately, and offers energy service at either a flat, non-seasonal price or a three-part TOU price structure. The customer can then adopt one of four renewable portfolio options that charge either an energy charge premium or a monthly fee.

Larger nonresidential customers at PGE are segmented by peak demand into three groups: 31-200 kW, 201-4,000 kW, and over 4,000 kW of peak demand. All rates feature demand charges. These customers are also offered more sophisticated pricing options. They can stay with a two-period slightly differentiated TOU energy charge or select a daily price option which provides TOU pricing based on "the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh US for wheeling, plus losses".[25] This example provides an illustration of utilities that offer limited access to wholesale market pricing while still providing full service.

[25] Portland General Electric, Schedules 83, 85, and 89.

HQD also appears to be somewhat unusual in its offer of Rate G-9, which offers service to Medium Power low load factor customers who would otherwise pay high prices under Rate M. Other utilities tend to impose lower demand charges than those of Rate G and M, and thus do not perceive the need to make special provision for low load factor customers. However, examples of such rates exist elsewhere, and HQD is not outside industry practice by offering such a rate.[26]

HQD's offer of additional electricity provides its customers with limited access to market-based energy in conditions when such energy is available. Medium-sized business customers in North American jurisdictions that allow customer choice permit such service in a less restricted manner, under a variety of commercial terms (varying with price fixity and duration of contract). Additionally, some utilities who remain vertically integrated offer such service through real-time pricing and other rates whose prices vary with short notice and have some connection to wholesale market prices or the utility's definition of marginal cost. HQD's circumstances are somewhat different from other jurisdictions due to the lack of variation in marginal costs in off-peak months. This fact reduces price uncertainty for the utility and, by extension, the customer. As a result, HQD can offer longer advance notice of pricing and can allow more time for application and approval of requests for additional energy.

Rate Design Issues and Approaches

HQD's Small and Medium Power rates do not particularly raise design issues, since their structures are similar to those of other vertically integrated utilities' small business rates. However, trends in markets with competition, and designs in some traditional jurisdictions suggest that HQD might experience pressure to provide additional options that might enhance service.

The basis for additional options would be broader interest in market-priced energy, which in turn depends on the level and the time pattern of marginal costs. HQD purchases its energy on the basis of flat contract prices, but the wholesale market still displays time variation and this time variation is experienced by Hydro-Québec in peak winter months. HQD may wish to explore some degree of peak seasonal, TOU, or demand response pricing to transmit price signals at high-cost times to customers who can control usage and reduce system cost in return for reduced bills. The reduction in costs would benefit all customers in the service territory by reducing the cost of purchased power.

5. LARGE POWER CLASS RATE DESIGNS

Current HQD Rates

HQD's rates for Large Power customers (those with demand in excess of 5 MW) share some attributes with those of Medium Power customers. The price structure is non-seasonal and a minimum billing demand is used in demand charges for all tariffs. Rates L and LG are very

[26] One example is Manitoba Hydro's Limited Use of Billing Demand tariff.

similar in structure and pricing. Rate L serves industrial customers with peak demand of 5 MW or more, while Rate LG serves customers of 5 MW or more whose load is predominantly non-industrial. The most noticeable difference between the rates is in the demand charge. Rate L's demand charge is based on contract power coupled with an optimization charge applied in the winter period if metered demand exceeds 110% of contract. Rate LG's demand charge is based on current metered demand coupled with a 75% ratchet on the last 12 months' winter peak demand.

The contract power provision of Rate L is not quite as onerous as it seems at first, since the customer can increase their contract demand a maximum of once per month, avoiding optimization charges but increasing their contract demand (and the minimum basis of the demand charge) for the ensuing year. (The customer may, of course, decide to pay the daily or monthly optimization charge, whichever is less expensive, and leave the contract power level unchanged. This methodology reflects the utility's concern to ensure that very large customers avoid unannounced increases in peak usage. From the utility's perspective, the contract demand represents the minimum level of its obligation to serve, but it also represents a threshold beyond which the customer reduces capacity that might be considered as necessary to meet fluctuations in demand. For smaller customers, unanticipated increases in demand may pose challenges for small sections of the distribution system. In contrast, for larger customers, such increases potentially pose a challenge to both supply and transportation capabilities.[27]

HQD offers a rate option for customers who can restrict their winter consumption during business days in the winter period. Rate H consists of an energy and demand charge that differ from other HQD rates. The demand charge has a 100% ratchet applicable to the previous 24 billing months, while the energy charge offers inexpensive non-winter weekday energy and energy at more than three times the price on winter business days. (The tariff prices are $0.0526 and $0.1808/kWh respectively.)

Another option is Rate LP, which is applicable only to customers as auxiliary power in conjunction with a fuel-fired boiler. This rate is thus end-use oriented. The customer signs a one-year contract for a minimum of 5 MW of peak demand and pays for energy under the same blended price formulation as is found in the Additional Energy Option.

Additionally, Large Power customers have available to them options similar to those available to Medium Power customers. These options include running-in and equipment testing provisions, the Additional Energy Option, interruptible service, and standby service. Provisions may vary slightly from those offered to Medium Power customers but the rate structures and pricing are fairly similar across classes.

[27] Another tariff difference is that Rate LG has a special provision for service to municipal distribution systems who serve Rate L and LG customers. In this case, HQD provides a discount that varies according to the power demand of these customers and that can be as high as 15%. That discount is provided to cover distribution costs of the municipal systems that serve these customers.

HQD Designs and Industry Practice

The traditional rate design for large customers is the customer-energy-demand rate, but the variety of retail rates currently available to large customers is broader than that available to other customers. This diversity arises from the size and industrial diversity of the customers, and the sophistication of customers, combined with the potential of electric power to constitute a significant share of total product/service cost. Major rate types include: 1) time-varying rates; 2) blocked tariffs; and 3) hours-of-use rates. Additionally, utilities offer numerous variants of interruptible and demand-response products. The largest customers also receive service under special contracts, rates tailored to their specific needs, and the occasional industry-specific tariff.

Given this diversity, HQD's large-customer retail portfolio appears to be well within industry practice with regard to most design characteristics. A few differences merit discussion.

First, HQD's rates display less price variation than most. This is likely due to the fact that system marginal costs have been at least partially insulated from market forces by transmission constraints to other service territories. Additionally, as a distributor making purchases that typically lack time variation, the opportunities to exploit external market opportunities are limited. The storage capabilities of HQD's reservoirs have diminished much of the time variation of marginal costs in the absence of trading opportunities with other service territories. As well, HQD purchases power from the Heritage block on a flat-price basis and does not face appreciable time variation in new generation wholesale prices. With a flat purchase price profile, it is not surprising to see a relatively flat retail price profile.

Second, HQD's rates feature relatively high demand charges when compared with energy charges, relative to other jurisdictions. The power-to-energy ratio was studied in 2004 and deemed appropriate, and may still be so.[28] Still, it may be worth reviewing this relationship to update this information.

Third, due to the relatively low variation in marginal cost, HQD appears not to have explored as deeply as other utilities the use of demand response pricing or price variability to signal customers the variability of price over time. This situation arises from the ongoing pattern of marginal cost in the Québec region. HQD does make use of the dual-fuel option (Rate DT) and interruptible provisions to secure load relief in hours likely to result in peak demand. It may be that there is scope to use short-notice pricing to induce greater response, provided that power purchases could be arranged with parallel pricing features. This would pass the price response-induced bill reductions of customers through to cost reductions for HQD and, presumably, cost reductions for its supply sources at critical times.

Fourth, HQD's use of contract power and the optimization charge is somewhat unusual, although it reflects the natural desire of the utility to avoid surprising large increases in demand that would pose a threat to system stability.

[28] See filed document R-3541-2004, HQD-1, document 3, pages 19 and 20.

Minnesota Power provides an example of how similar concerns are handled in another jurisdiction. Their Large Power Rate features a ten-year Electric Service Agreement in which customers state a monthly firm demand level greater than 10 MW and less than 50 MW. Demand in excess of 50 MW requires a written commitment for five years and is subject to a Large Power Surcharge, whose price is calculated as part of the contractual addition and is based on a computation of the expected incremental capacity and energy cost to serve the added load. This utility, located in northern Minnesota, is unusual in that its system load is dominated by a relatively small number of very large customers. It offers a useful illustration of the necessary contractual requirements that can develop in serving very large customers in relatively remote locations. (Minnesota Power's service territory lacks large customer populations that can stabilize the loads of more conventional systems.)

Rate Design Issues and Approaches

HQD's current approach to pricing suggests that there are several rate design issues that bear review. These issues arise partly from the rate design differences noted above but partly from other general pricing issues.

Pricing Differences Between Rates L and LG. As noted above, there are two pricing differences between these two rates: 1) Rate LG retains a ratchet on its demand charge while Rate L uses contract power in combination with the optimization charge to control demand by pricing excess demand at a premium, and 2) Rate L has slightly different—lower—prices than does Rate LG.

The differences in the pricing of demand appear to be tailored to differences between the two customer groups. Rate LG serves non-industrial customers, mostly in urban areas at the center of HQD's distribution network. With the exception of a few municipal accounts, most are not so large that changes in peak demand would threaten system stability. The load of municipal customers is likely to be stable too, consisting as it does mostly of the loads of many smaller customers. In contrast, Rate L serves industrial customers who can be very large and who are quite often found in relatively remote locations. They constitute a greater threat to system stability than does the average Rate LG customer.

Both demand charge structures impose a significant charge for demand growth, but the optimization charge likely involves a larger long-term impact on the customer's bill. Operationally, the optimization charge also requires closer contact with the utility and a better chance to consider options before a demand increase. Thus, the price signal of each demand charge appears to be tailored to the characteristics of the customers in each rate. HQD's use of contract power and an optimization charge does not suggest an immediate need to reconsider this structure, although market-based pricing alternatives or supplements might improve pricing efficiency in periods of low system reserves.

The pricing differential between rates arises from questions of competitive price pressure on industrial customers. Until 2014 all these customers were served under Rate L, but differences arose because of perceived competitive threats to industrial customers relative to non-industrial customers. The central challenge arises from a slow but steady increase over time in HQD's retail prices relative to other service territories' prices. Downturns in many commodity prices and rising prices of a significant input, electricity, have slowly eroded the competitiveness of Québec's industrial customers. The two rates were created to enable the utility to assist industrial customers to meet competitive threats by lowering the trend in average supply prices relative to the prices charged to other rate classes.[29] The differential between the prices of Rates LG and L is proposed to grow slightly in April 2017 and it is anticipated to continue to do so thereafter.

Traditional rate designers would see no difficulty in the split between industrial and non-industrial customers, due to historical differences in load profile. Thus, one preliminary approach to reviewing this issue might be to evaluate the two rates groups' cost to serve and engage in non-proportional rate change based on this (possible) cost difference. In all likelihood, Rate LG customers are more likely to have more peak coincident load profiles and thus have a higher cost to serve than would the industrial customers of Rate L.

A second, indirect approach would involve attempting to alleviate the overall pricing issue of cross subsidy across rates. Resolution of this problem would require a phased convergence in revenue-to-cost ratios. Both of these approaches would move prices in the direction of embedded costs.

If improvements in cost allocation cannot readily be made in a timely manner, a third approach that improves price efficiency but not average price might offer potential for cost control for those able to manage their pattern of usage, a scheme which Rate L customers might be able to use to their advantage. This approach involves more thoroughly exploring the use of time-varying rates reflecting regional marginal costs. The pricing plan of Rate H, which induces customers to avoid winter weekdays is a step in this direction.

Pricing for Special Industries. HQD currently offers special industry pricing to greenhouses and receives inquiries from a number of industry groups for special pricing consideration. This review is not tasked with examination of these arrangements or requests. However, it is possible to review briefly the industry perspective on this issue. A conventional objection of regulators and intervenors in rate applications arises when utilities attempt to price customers by industry, or more generally to segment customers on the basis of cost differences (or sometimes non-cost differences). A traditional argument against segmentation is that customers ought to be grouped in large classes in the interest of price uniformity and rate simplicity, and also because the more finely drawn the rate class, the more arbitrary and volatile the cost allocation can become from rate case to rate case. If large classes are kept whole, cross subsidy within groups will still occur but will be considered practical and "fair", or in the interest of societal objectives.

[29] The introduction of the LG rate was imposed by a change in the *Loi sur la Régie de l'énergie*. All non-industrial customers were transferred to Rate LG as of April 2014. While other classes' Heritage Pool prices have started to be indexed for inflation, the index for Rate L customers has not, inducing a cost shift to other rate classes.

Still, utilities (and regulators) face constant requests for treatment to alleviate special concerns and to rectify perceived inequities in cost allocation. To some extent, rate diversity manages some cost differences. A simple energy-only rate will not recognize cost differences arising from load factor differences across customers. However, a standard energy and demand rate will achieve much of the necessary price differentiation occasioned by cost differences. Accurate allocation of costs by voltage service level helps as well in the case of customer and service differences by voltage level.

Additionally, utilities sometimes have the ability to offer special contracts for unique large customers. An established utility approach to this problem that does not involve special contracts (and cannot for all but the largest customers) is to ensure that the retail portfolio contains rate alternatives sufficient to cover the much of the diversity of customer needs. This argument is cost-based, but also takes into account customers' tolerance for price risk and willingness to commit to contracts of differing durations. Among large customers of conventional utilities, a portfolio that offers flat pricing, time-varying pricing (seasonal or TOU, as justified by cost variation), and perhaps demand response or other marginal cost-based pricing will allow customers to select their preferred products.

All these perspectives rely on differences in costs and preferences across customers. However, some industry special pricing requests are not related closely to cost but instead to social or other objectives of regulators, intervenors, or the utility. Some of these are related to competitive opportunities or economic distress. The next section discusses rates of this type, which reduce revenue-to-cost ratio on specific customers in the hope that secondary benefits will help the utility to avoid cost increases for other customers.

Other types of requests for industrial special treatment are to be avoided, based on industry practice. The obvious difficulty is that once a subsidy with no termination date is established, it is difficult to remove. Additionally, it invites other requests for similar special treatment. Some cases, for example pricing in remote communities in Canada, continue to enjoy wide support. However, in this instance, the customers' remote situation and lack of connection to the grid does not give other customers an argument for special treatment.

Some special pricing requests can have this potential. There are rare examples in North America in which some customer group has obtained entitlement to power from a certain source, rather than entitlement only to the power procured by a retail provider for all its customers collectively. Sometimes this occurs with renewable power, but this is a case of customers paying to have access to premium-priced power. Special allocation of discount power is rare and difficult to sustain.

6. OTHER HQD BUSINESS RATE DESIGNS

Economic Development and Load Retention Rates

HQD's Current Rates. HQD offers an economic development rate (EDR) to customers in its Medium and Large Power classes. The rate provides a discount on significant increases in consumption for a fixed period of time to both new and existing accounts. A customer can request a discount if their planned increase equals or exceeds 1 MW peak demand or 20% of existing load, their electricity costs are at least 10% of operating costs and the site commences consumption of electricity within three years of the EDR commitment.

The initial rate reduction is 20% of the incremental bill (the total bill for new sites) and the reduction tapers down to zero by the end of the contract period, including a three-year, 5% change per year pattern at the end. One anomalous provision appears to be the presence of a terminal date for EDR service (March 31, 2024) by which time all discounts need to reach 0%. However, HQD has the right to request a change of the terminal date during a rate case application. Approval of a sequence of terminal dates would produce a rate design similar to EDR designs with no terminal date, provided that the date revision does not extend the length of current EDR contracts.

HQD also offers a load retention rate (LRR) option, for Large Power industrial customers only. The option provides rate discounts to customers who can demonstrate that their business is experiencing financial difficulty. Applicants must provide three years of historical financial data and prospective financial information as well, and then must demonstrate that they have sought and obtained discounts from their suppliers and collaborators. Those who obtain approval receive 12 months of a rate discount that is a cost-weighted average of the discounts that the customer has obtained from its suppliers. Customers can obtain another 12 months of discounts beginning no more than 12 months after the end of the first discounted year, but the discounts taper to zero over these 12 months. In this second year, the discount can be no more than a 10% reduction in the electricity bill. Customers can apply a second time for LRR service 60 months after the first two years, under the same rules, but not thereafter.

Industry Practice. Most North American utilities offer an EDR while a much lower number offer an LRR. Many EDRs provide the sort of tapered rate discount seen at HQD. A review by CA Energy Consulting in 2012 of ten United States utilities, both investor-owned and public, found contracts mostly of four to five years' duration. About half required promises in writing of certain levels of job creation and almost all required specified planned load building. Most utilities required a minimum addition, with a range of 250 to 3,000 kW. The price terms of the EDRs reviewed provided percentage discounts on the base bill in about half of cases, and on just the energy or the energy and demand charges in other cases. HQD's EDR tariff is well within industry practice.

Utilities that offer LRRs provide a variety of price discounts that have a time limit of some sort in order to avoid permanent cross subsidy. Most LRRs require documentation justifying the discount, sometimes in the form of net benefits estimates, but sometimes due to, or prefaced by, information on competitive price pressure.

HQD's tariff option appears to have contract time restrictions similar to those of other utilities. However, it appears to differ somewhat from other utilities by not serving the same customer classes as the utility's EDR.[30] Additionally, the LRR's discount limitations appear to be more specific than those of other LRRs.

Issues. EDRs sometimes face a challenge of the percentage discount on the bill distorting the utility's energy charges. In cases where a tail block of a blocked rate, or some time period of a TOU rate, has a price based in some fashion on marginal cost, there is a risk of selling at a loss. Utilities in these situations sometimes alter the terms of a discount to avoid this outcome.

One way to achieve this objective is to place applicants for EDRs on two-part RTP (which is feasible if the utility already has such a program). Two-part RTP consists of 1) a "base bill" that is calculated by applying standard tariff prices to a contractual set of hourly loads and monthly peak demands, collectively known as the customer baseline load (CBL) and 2) an "incremental energy charge" in which hourly marginal cost-based energy prices are applied to the difference between actual and contractual hourly usage. Under an EDR based on two-part RTP, the customer pays a discounted base bill, but then faces the same energy price on load increases or decreases from the hourly CBL energy value as other RTP customers. This approach is taken by one of the utilities reviewed in our study.[31]

For LRRs, the same issue of price distortion applies. However, in most cases where LRRs apply, this price distortion is likely to appear inconsequential to both the customer and the utility. Again, a two-part product reduces the margin on retained load that would otherwise be likely to disappear, but encourages load changes that control system costs.

Another issue regarding EDRs and LRRs involves whether utility or market conditions should influence these rates. Some utilities are located in markets where strong growth is normal while others find themselves in regions of ongoing economic distress. Additionally, electricity markets can feature tight supply or energy surplus situations. These circumstances will affect the volume and mix of applicants along with the pricing that can be offered. HQD faces circumstances of relatively tight supply in peak winter hours but significant surplus otherwise. These circumstances can be reflected in EDR pricing especially, beginning with a seasonal component, based on the judgment of utility costing and pricing staff.

If a distributor earns no return on generation and transmission services, then granting EDR or LLR applications would be based only on the net income impact of the decision, including all direct and indirect impacts. Discounts would be granted on the distribution portion of the

[30] The EDR is available to Medium and Large Power customers while the LRR is available to Rate L customers only.
[31] In principle, the marginal energy could be priced at something other than hourly short-notice prices. However, the inducement to manage incremental load may help to achieve acceptance of the EDR by customers not participating in the rate because the incremental load of participants will avoid increasing system peaks.

customer's bill. Under such circumstances, electricity surplus conditions would play no part in the decision.

If the distributor's electricity supplier were willing to lower the cost of supply for the EDR/LRR contract, or if a regional or provincial government were willing to provide a subsidy reflecting additional social benefits, then the supply portion of the bill could be discounted as well. In practice the attraction of new load or retention of distressed load is usually a collaborative effort between the utility and various levels of government. However, the utility should be compensated if it is the conduit of some of the discounts offered.

In this case, if HQ's production arm were willing to reduce its energy costs, perhaps charging HQD at wholesale price for incremental usage, then HQD would be able to pass such savings through to the customer.

An additional issue common to EDRs and LRRs is the challenge of excluding customers who would also like a discount. Existing customers, perhaps competitors of the new EDR load or the load granted relief via the LRR, will wonder why the same discount cannot be provided to them. Utilities meet this challenge with minimum size restrictions (to avoid large support costs being applied to many small customers) and documentation requirements demonstrating commitments and need. HQD "fences out" applicants with documentation requirements that appear to be more stringent than average. In particular, the LRR requirement that the discount be an average of discounts granted to other suppliers of the distressed customer is a powerful constraint on LRR applications.

The EDR/LRR challenge is not only to develop a flexible rate design that can process applications and exclude those who might want to seek a discount regardless of their plans, but also a process challenge, that permits objective evaluation of the impacts of granting pricing concessions and the development of price concessions in such a way that the distributor does not have to absorb discounts more than it would be prepared to provide on its own.

Interruptible/Curtailable Rates

HQD's Current Rates. HQD offers interruptible service to its Medium Power customers under a contract that pays customers partly to be available for curtailment of load and partly for actually curtailing during hours when HQD calls an interruption period. A customer with at least 1 MW of peak demand can offer a minimum of 20% of its peak demand for interruption, specifying a "base power" amount of kW (a "firm power level," using the generic industry term). During periods of interruption the customer must reduce usage to the base power level. Customers have two service options.

- Option I permits interruptions in all winter hours, with the utility providing two hours' notice on weekdays and notice by 3:30 pm of the previous day on other days.
- Option II permits interruptions in a limited set of winter peak hours only, with the utility providing notice of interruption by 3:00 pm of the previous day.

The two options have a maximum number of 100 hours of interruption per season, but Option II allows more possible interruptions, since interruptions will likely be shorter than in Option I. Both options have penalties for overruns of 105% of base power during hours of interruption, and these penalties can rise as high as the value of the fixed credit; four or more overruns are grounds for cancellation of the service to the customer.

This type of interruptible contract is also available to Rate LG customers, while Rate L customers can select this rate design as well, provided that they select Option II only (interruption calls in limited peak hours only).

HQD offers a different interruptible service option for its Rate L customers only. This option pays customers in the same fashion, for availability and for response during interruptions. However, the basis of payment during interruptions is reduction of usage from the level of peak demand. Again, there are two options, but different in nature from the Medium Power interruptible options. In this case both options permit interruptions in all winter hours, the utility provides two hours' notice on weekdays and notice by the preceding 3:30 pm on weekends. However, Options I and II differ in hours of interruption:

- Option I permits a maximum of two interruptions per day, twenty per winter season, and a maximum of 100 hours per season. The customer is allowed a minimum of four hours between interruptions.
- Option II permits a maximum of one interruption per day, ten per winter season, and a maximum of 50 hours per season. The customer is allowed a minimum of 16 hours between interruptions.

Clearly Option I permits the utility to interrupt for more hours than the other option, although the terms of notice are identical. Naturally, Option I's prices are systematically higher than Option II's:

- Option I provides a $13/kW per winter season fixed credit for participation and availability, and graduated energy credits for energy actually curtailed. The credit rises from $0.20/kWh to $0.25/kWh to $0.30/kWh as the hours of interruption pass the benchmarks of 0, 20, and 40.
- Option II provides a $6.50/kW per winter season fixed credit and a flat $0.20/kWh variable credit for actual curtailment.

As with the Medium Power rate, overruns result in a penalty, with repeated overruns potentially eliminating the fixed credit. Three overruns are sufficient to expose the customer to possible cancellation of the interruptible service contract.

HQD is also offering a commercial program this winter called *Gestion de la demand en uissance* (GDP).[32] The program is available to all customers on Rates G, M, DM, and LG (but not L) but not taking interruptible service. Customers can reduce their bills by reducing usage below a

[32] The English language web page labels the program "Demand-Side Management".

baseline level at times of curtailment determined by HQD. The utility pays $70 per kW-year for the average reduction in usage across the hours of curtailment.[33] This credit price is based on an independently determined capacity price. Curtailment periods are to be three to four hours in duration and notice will arrive at least three hours in advance. HQD can call no more than 100 hours of curtailment per winter. The program is couched in the language of demand-side management. To participate, a customer must submit a project description for peak load reduction of more than 200 kW. If approved, and curtailment calls take place, the customer is paid their average load reduction multiplied by the $70. If no calls occur, the customer still receives 15% of the product of their maximum winter power demand multiplied by $70. Those who fail repeatedly to curtail when called are dropped from the program and not provided a credit.

Industry Practice. HQD's interruptible service plans (excluding the GDP plan for the moment) are similar to those in the industry in that most traditional programs provide a demand charge (kW-based) credit for participation. The firm power level approach is generally more widespread than the interruptible demand approach but both are in use. Traditional interruptible/curtailable rates do not provide payment for load reduction during interruption periods, although the emergence of wholesale markets that admit load curtailment have spurred utilities to offer this feature, in return for reduced demand credits.

HQD is unusual, though, in its use of a more sophisticated and more complex approach to the determination of the kW and kWh bases for payment of discounts to customers. Traditional rates award discounts predominantly on the basis of the difference between a definition of peak demand and the customer's selected firm power level. HQD's Medium Power interruptible rate calculates the fixed credit based on the difference between "average hourly power during useable hours" and base power (the level of firm demand chosen by the customer). The average hourly power amount is calculated across all the hours of the peak-defined hours in the billing period when an interruption could have been called but wasn't. This representation of the customer's available power is an improvement on the traditional measure of peak demand, but requires a computation not usually made by utilities.

The computation of the interrupted usage involves aggregating, for each hour of interruption, the five highest hourly usage values in the same hour on weekdays/weekend days in the billing period and subtracting the average (of four 15-minute values of) hourly power during the interruption hour. That is, the utility obtains a representation of curtailment from similar hours on other days when interruptions do not occur. This approach is thus a baseline load representation and customers are paid to reduce usage. This payment is not just to a contracted amount of reduction, but to whatever reduction the customer chooses to provide, another, subtler, improvement in design.

The structure of payment for the Large Power (Industrial) customer group is even more sophisticated. In this case the fixed credit is paid on "effective interruptible power," which is an estimate of the customer's ability to reduce usage. It is the product of "interruptible power,"

[33] The price is derived from New York State's Unforced Capacity estimates.

the customer's claimed commitment to reduce usage and the "contribution coefficient" for the billing period. The contribution coefficient is a load factor-adjusted reflection of ability to deliver the claimed interruptible power.

The payment for actual load reduction is based on "effective hourly interruptible power," which is the difference between maximum power in the billing period, adjusted by the contribution coefficient, and the average hourly power during the interruption period.

Thus, relative to other utilities, HQD has striven for balance between payment for participation/availability and payment for actual load reduction.

HQD's new GDP program for commercial customers appears to strive for balance between payment for participation and for actual load reduction. However, in this case the weight is primarily on the side of payment for participation, as it is intended to induce customers to undertake expenses to facilitate response.[34]

Issues. A traditional issue in interruptible/curtailable pricing used to be that utilities would pay for availability but not performance. The outcome would be that, at the end of a peak season, either the utility would be "out of the money", having paid for availability and potential response but never having called an interruption, or the customer would be "out of the money" having been paid for availability but received nothing for having delivered curtailment in a season when many curtailment periods occurred. That issue is not present in HQD's rates.

One possible issue, though, is pricing for the service of interruptibility, whose value changes with each year, based on forecasted system conditions. Forecasted values of capacity and energy in peak hours can be used to determine in advance of each season what the fixed and variable credits should be. This approach is more market-based, but requires the utility to solicit participation each year after posting the coming peak season's prices.

An extension of this question is whether utilities should pursue for large customers the equivalent of critical-peak pricing or peak-time rebate programs, which are offered to small customers in some jurisdictions. In this case, customers are placed on market-based rates (with stated advance notice) for periods of interruption, but are otherwise on their standard tariffs. Under CPP, customers receive a bill discount to participate and then face the market price on all usage in the interruption period. Under PTR, customers receive little or no discount but either pay or are paid for load increases or decreases from a baseline value. Both structures tend to do away with penalty provisions and the PTR format eliminates the need for maximum limits on hours of interruption, since a customer who does not modify their usage has no bill risk. If such voluntary response programs are added to existing interruptible rates that impose

[34] For example, a customer who reduced usage by 500 kW for 10 hours would receive $70*500 = $35,000. Assuming that marginal cost is $0.30/kWh, the utility will have reduced its costs by 500 kW * 10 hours * $0.30/kWh = $1,500, leaving the residual $33,500 as a payment for availability. Even if curtailments occur for 100 hours, the cost reduction for HQD is $15,000 and the availability payment is $20,000.

strict quantity constraints on customers, the pool of available interruptible load can be expanded.

Such products represent a more market-based approach to interruptible service. HQD comes close to this sort of structure, except that its prices are announced with each rate case, although they are based on an appraisal of the value of interrupted load prior to the filing.

Standby Pricing

Standby rates provide service to customers who have their own on-site generator and that serve a portion (sometimes all) of their needs. Whenever their generator is shut down for maintenance, experiences unplanned outage, or otherwise produces power at less than capacity, these customers can obtain energy and capacity from the utility under the standby rate. Customers' generators can include stand-alone units or combined heat and power units that are part of a manufacturing process.

HQD's Current Rates. HQD offers standby service to Medium Power customers through Rate GD, and to Large Power customers through Rate LD. These rates differ in complexity and purpose.

Rate GD offers backup service to customers via a low demand charge but one that carries a 100% ratchet on the preceding 24 months of service, and relatively high seasonal energy prices. The demand pricing scheme appears to require that the customer reduce their usage by the same amount as they reduce site generation when maintenance is necessary. The energy pricing scheme encourages customers to restore their site generation to service as rapidly as possible.

Rate LD is more comprehensive in its coverage, specifying pricing that differs between periods of planned site generation outage and unplanned periods. The rate is also explicit in stating that supplemental power (power used beyond the normal site generation capability) will be priced at Rate L. Rate LD offers service on a firm and non-firm basis. Firm service includes a small demand charge based on monthly peak billing demand and two energy prices, a high price for winter weekdays and a low price for other periods. The price ratio is in excess of 3:1.

Non-firm service is priced based on hourly demand charges, differentiated between planned and unplanned period peak demands and an energy charge identical to the "other hours" price of firm service.

In both rates, the 100% ratchet on the firm-service demand charge indicates the use of a "reservation charge" approach that collects contributions to fixed costs based on the peak demand value representing the utility's obligation to serve the customer with site generation capability. The non-firm service demand charge uses the daily structure to encourage limited use of HQD energy.

Industry Practice. Standby rates are characterized by a wide variety of structures and definitions of peak demand used for pricing. A loose definition of traditional standby rates would state that they include a reservation charge based on a contract level of demand, and a charge or charges for the provision of backup and maintenance service to the level of the nameplate capacity or some other agreed upon definition of capacity. Prices for backup and maintenance service are usually substantial, created as incentives to encourage the customer to restore their site generation unit to service as rapidly as possible.

Demand and energy beyond this level are usually termed “supplemental” and are often priced at the underlying standard tariff. Standby service can be structured as a rate or rider, the latter making more direct reference to the underlying rate’s pricing.

Issues. Some, but not all, utilities make use of ratchets for the computation of the reservation demand. However, advocates of site generation focus on ratchets as a leading deterrent of investment in site generation, since they tend to create a fixed cost obligation that advocates feel overpay utilities for distribution services.

Some recent standby rates, notably those of Kansas City Power & Light and Georgia Power, make use of two-part RTP rates to serve as their standby tariff.[35] The customer establishes a customer baseline load based on past usage and peak demand and a base bill is developed on this basis, using a standard tariff. The customer is then free to choose, based on market-based hourly pricing, when to conduct maintenance and how to respond to an unplanned outage. In high-priced hours, the customer may elect to curtail production, while in low-priced hours the customer may elect to purchase from the utility. This approach tends to be simpler than the traditional approach since it avoids the need for separate price estimates for the various types of power use.

A few standby tariffs offer replacement power, which is power made available at market prices when the customer deems such power is less expensive than site-generated power. Among the few utilities offering replacement power, at least one places significant restrictions on the availability of such power and requires that the utility engage in planning before approval. In contrast, an RTP rate allows the customer to opt for replacement power whenever supply from the grid is ample and inexpensive.

Thus, it appears that HQD’s standby rate designs, while not as market-based and flexible as an RTP tariff, still offer rate structures that are commonly found in the industry. The 100% ratchet feature may be viewed with skepticism by site generation advocates, but such a ratchet may be justified by the fixed costs of offering standby service. HQD may be called upon in the future to defend its reservation pricing in some detail. However, the option to choose firm or non-firm power provides some degree of choice for the utility’s customers.

[35] Georgia Power has a standby tariff, but no customers are served under it. All standby customers make use of RTP.

Electric Vehicle Rates

HQD's Current Rates. HQD currently offers no special pricing for electric vehicles, either in private residences or at public charging stations. However, in their recent filing, they proposed to introduce an experimental tariff, Rate BR (for *"Bornes de Recharge"*, in English, charging stations).

HQD supplies energy for vehicle charging at public 240- and 400-volt charging stations owned by the firm Circuit Electrique/Electric Circuit in Québec.[36] HQD determines pricing to this company, but the charging station owner determines the charging scheme for its customers. As of February 1, 2016, the charging station owner charges on a fee-per-session basis, $2.50 for the 240-volt charger, or at an hourly fee of $1.00, with billing based on number of minutes of connection. The basis for payment varies by charging station. The 400-volt charger costs $10 per hour.

HQD's proposed Rate BR is a hybrid designed to stand between its standard tariffs and its standby pricing.[37] The experimental rate is partly an hours-use-of-demand (HOU or HUD) tariff in which improving load factor reduces the average price that the customer pays for electrical energy, regardless of customer size. An advantage of this structure is that the utility can meter and bill such customers using a traditional demand meter. As customer size (as measured by peak demand) increases, average price increases. HQD's filing presented illustrative bills for customers of 50, 70, and 100 kW, and with load factors from 2% to 10%. Average pricing for a 50 kW customer was $0.11/kWh for all load factors, but for a 70 kW customer ranged from $0.138 to $0.129/kWh, and for a 100 kW customer ranged from $0.158 to $0.143/kWh. At 50 kW or below the rate is flat, but above that level the HOU features set in.

More generally, the rate ties its pricing to Rate G for small customers, Rate M for larger customers and Rate G-9 for larger customers whose load factor increases above 10%. Thus, the rate strives to provide sensible price incentives to customers while collecting contributions to overhead that are similar to those of customers on the base tariffs and of like size.

Industry Practice. With regard to service at private residences, some utilities offer stand-alone electric vehicle charging rates while others rely on existing tariff options. The key to this choice is whether one of the utility's current residential rates has TOU variation that encourages charging in off-peak hours. The utility either uses such a rate option for residential customers, or develops a TOU electric vehicle charging rate. Again, HQD's lack of cost variation except in peak winter hours is likely to set the utility's pricing structures apart from those of conventional utilities.

More sophisticated demand-response approaches are under discussion, as well. A simple approach involves placing the charging mechanism under a CPP-type rate (which the home may already use). In this case, the customer could set up automatic programming to stop vehicle charging in critical-peak hours, or any hours other than off-peak. A variant of this approach is to

[36] See https://www.lecircuitelectrique.com/charging-stations-and-rates.
[37] HQD filing R-3980-2016, *Stratégie Tarifaire*, Original 2016-07-28, HQD-14, document 2, section 4.

have the car itself control when charging occurs. A still simpler approach is for the utility to serve the home charging station under direct load control, perhaps with a customer override switch in case of need.

A further element of offering residential electric vehicle charging services is the cost of equipment changes that facilitate charging. This can include the installation of a charger, upgrades to the service at the house and, eventually, upgrades in the distribution system serving the area. This challenge is generally viewed as being separable from the issue of the pricing of energy services, and the degree to which these costs are assigned to the participating customer can be resolved in a variety of ways.

With regard to service in commercial settings, there is considerable uncertainty about how to price electricity. Public electric vehicle charging stations are sometimes operated by the electric utility in the jurisdiction or a competitive service provider, but sometimes by a third party if resale of electricity is permitted in the jurisdiction. The challenge for the utility is to develop a rate that recovers its costs from the third-party provider of charging services.

Retail charging alternatives are quite varied. At present, some vehicle charging is free, while other providers seek payment on a pay-as-you-go basis. Still others adopt a subscription basis for access to their charging stations. Not all United States jurisdictions permit per-kWh pricing as an acceptable form of pay-as-you-go. In these cases, payment can be on a dollars-per-charging-session basis or on the basis of charging time.[38]

Providers that use kWh pricing seem to use an energy charge-only approach, with no customer charge involved. Thus, recovery of fixed costs must occur through the energy charge, in the same manner that gasoline is priced. (Conversely, the cost-per-session approach recovers the variable cost of charging in the form of a fixed charge, while the charge per unit of time is something of a hybrid, with time being a proxy for quantity of energy.[39])

Another element of pricing diversity is related to technology. Charging stations and the cars they supply have varying capabilities for transferring energy per unit of time. This complicates the pricing of energy per unit of time or per session, relative to the simple volumetric approach to pricing adopted by other fuels.

Additionally, pricing within a utility jurisdiction depends upon the nature of the industry structure. In cases in which the utility is the only provider, the traditional regulated pricing model may still apply. If multiple providers can purchase energy in competitive wholesale markets, then regulation is not appropriate or necessary.

Issues. Pricing issues for residential service include: 1) the impact of EV service on the cost to serve a residential customer; 2) the degree of subsidization to offer residential customers to adopt charging service; 3) the ways in which residential customers should be charged for the

[38] Brad Berman, *The Ultimate Guide to Electric Car Charging Networks*, Nov. 25, 2014, http://www.plugincars.com/ultimate-guide-electric-car-charging-networks-126530.html
[39] Time is not a good proxy for energy because batteries charge at a decreasing rate over time.

marginal distribution costs of installing charging capability; and 4) the degree of pricing variability to offer customers.

EV service adds a substantial block of energy to customer load and, depending on the timing of the charging cycle, can significantly influence peak demand. At HQD in winter, charging in the early evening would add to peak demand, and even overnight would add to potentially large space heating-related levels of demand. This threatens to further segment the Domestic class and complicate its rate design. Separate metering and a separate tariff offer possible simplification, but this presumes that the EV customer can be identified readily.

Regarding subsidization, as noted above, this is a separable issue from the pricing of energy services and has a political/social optimization element. Questions about the sources of energy used for overnight charging (especially coal in a world that lacks a carbon tax) complicate pricing of standard or special EV charging rates. However, the use of off-peak market-based pricing appears desirable as a starting point.

The pricing of distribution services presents a second challenge. Traditional distribution pricing has socialized distribution costs without regard to location but has tended to differentiate cost by voltage service level. In this case, electric vehicle purchases can impose costs directly assignable to the customer receiving service, but will also eventually impose indirect costs on the entire distribution grid. Traditional distribution pricing may suffice to cover these costs or some share of them may be assigned directly to customers adopting EV service.

Regarding pricing variability, a simple TOU structure seems satisfactory for the present for conventional utility marginal cost conditions, especially if customers are offered CPP/PTR options that allow a customer to stop vehicle charging in unexpectedly high-priced hours, at the owner's discretion. For HQD's pricing of residential EV service, a CPP approach embedded within a flat price might be reflective of the pattern of costs.

Pricing issues for commercial charging appear to depend upon resolution of technical and institutional issues. Assuming that per-kWh charging becomes legal, this approach seems closest to the approach for pricing of other vehicle fuels. However, one could imagine development of a monthly customer fee (a loyalty fee) that would reduce the energy charge portion of the bill, bringing pricing closer to marginal cost. Competitive markets will presumably resolve which pricing arrangements survive and prosper.

For the utility determining how to price service to a provider of charging services, one approach might simply be to aggregate the load of a customer's multiple sites and serve them under a standard tariff. However, this might be problematic for grid management, since the sites will be dispersed. Additionally, for small providers of charging services, standard tariffs, with significant demand charges might prove onerous. Also, the very low load factors of customer accounts preclude this approach for some utilities, including HQD.

Traditional standby rates would not be particularly helpful either, since they penalize heavily intermittent, unpredictable spikes in usage. An all-energy time-varying rate might underprice capacity unless it is of the two-part variety, in which case the customer pays a lump sum to cover customer- and demand-related costs and then pays for energy-related costs according to a TOU or RTP structure. This would permit a utility with conventional cost variability to deliver an efficient price signal to the third party provider. The third-party provider could then devise whatever pricing scheme recovers their investment and manages their risk. In this case, the pricing challenge for the utility and customer is to agree upon the level of demand charge to impose. As with standby pricing (discussed below) the two-part pricing concept helps to alleviate the demand pricing issue.

HQD's experimental design (Rate BR) compares favorably with the two-part concept due to its metering simplicity and familiar declining block structure. The HOU design offers the advantages of blocked pricing for customers with a wide range of sizes. In fact, it is accurate to characterize HOU designs as customer-specific blocked pricing. Additionally, the rate provides each BR account with a relatively simple bill, consisting of a customer charge (if desired) and an energy charge, which provide a relatively simple basis for pricing at retail. Note that for larger customers, the bill isn't entirely free of risk for the provider, since variations in load factor can lead to variations of up to 1¢/kWh in average price. However, most charging stations likely will have fairly stable load factor since peak kW likely will be limited by the number and charging capacity of the charging stations.

7. SPECIAL CASE: DISTRIBUTED GENERATION

Background of Distributed Generation Trends

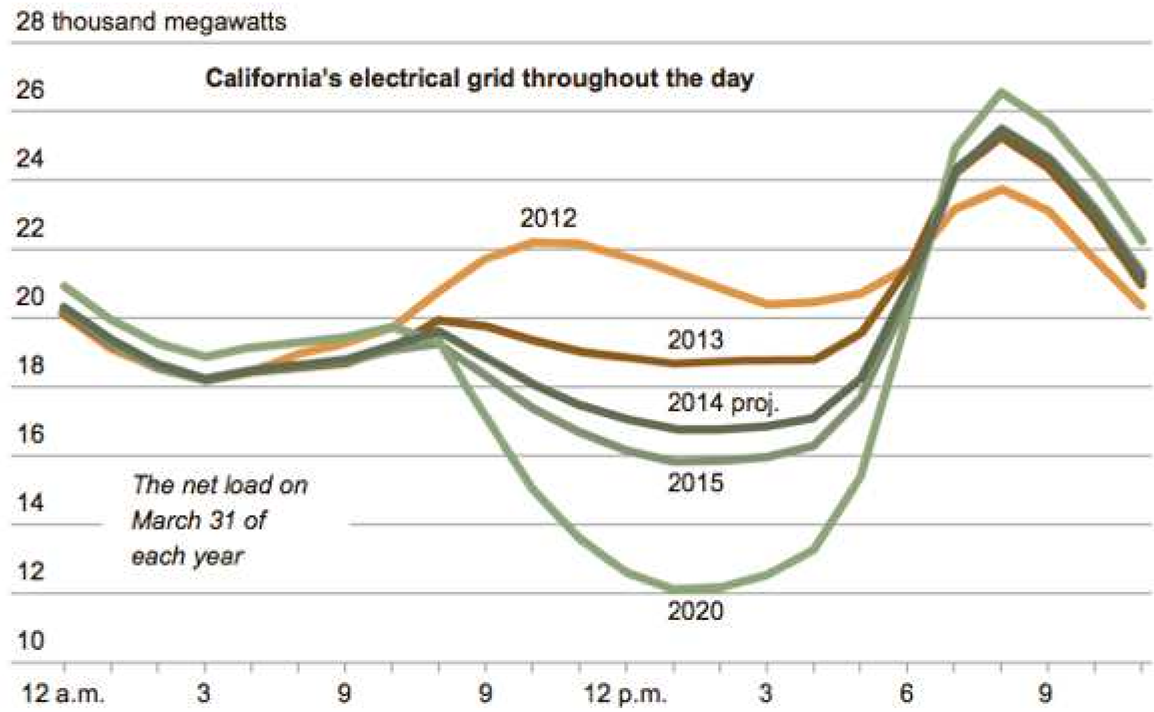
"Distributed generation" (DG) refers to generation that is generally located within distribution systems (rather than being attached to a transmission system) and that is generally located at customer sites (although it can also be located at "community" sites accessible to many customers). Environmentalists have enthusiastically embraced DG as a means of promoting solar and cogeneration resources.

Partly because of substantial subsidies, mass market customers, mostly from the residential class, have enthusiastically explored the benefits of locating renewable generation, chiefly photovoltaic solar power, at their sites. Solar DG customers maintain their traditional connections to the grid and generate electricity in daylight hours. At peak hours of sunlight, a customer can often generate more than the site uses, and thus has the capability to deliver energy to the grid, reversing the flow of energy in the part of the distribution grid closest to them.

In some regional power systems, solar energy's market penetration has now reached levels that materially affect the timing of system peaks and overall need for generation at peak times. One example of this phenomenon has occurred in California, where solar power has transformed the system load profile from a conventional daytime peaking shape into the "duck curve", shown in **Erreur ! Source du renvoi introuvable.**2. This shape occurs because solar generation during the daylight hours has substantially reduced the need for non-solar generation during those hours. This phenomenon has created power system control problems: in the middle of the day, non-solar resources need to reduce their outputs to levels that might be below their minimum physical capabilities; while the evening ramp-up in net demand strains non-solar resources' ability to rapidly increase output. These demands on non-solar resources entail costs that should ideally be paid by the solar resources that create the problems. The figure shows that California's duck curve has become more pronounced over time as solar resources grow in capacity, and is projected to continue in the same trend through 2020.

Figure 2

Net Demand for Non-Solar Generation on March 31 of Each Year, 2012-2020



Source: CallSO

Another example of this phenomenon can be found in Hawaii, where the system peak has been moved into the early evening from the late afternoon.[40] Hawaiian Electric proposed in November 2015 the residential TOU rates displayed in Table 1. Note that the cheapest time period, on most islands, is now the Mid-Day period between 9:00 am and 4:00 pm, less expensive even than the "Off-Peak" nighttime period.[41]

[40] The "duck curve" is well documented. The following reference is from the California ISO: https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

[41] Data extracted from: https://www.hawaiianelectric.com/hawaiian-electric-propose-expanded-time-of-use-rates.

Table 1
Hawaiian Electric Proposed Residential Time-of-Use Rates (cents per kWh) – November 2015

Island	Mid-Day (9:00 am-4:00 pm)	Off-Peak (Midnight-9:00 am)	On-Peak (4:00 pm-midnight)
Oahu	13.4	16.0	38.5
Hawaii	17.2	19.3	47.9
Maui	17.1	20.2	39.0
Molokai	21.6	21.6	44.8
Lanai	26.5	25.7	42.3

Note that California and Hawaii both offer substantial subsidies for solar power. Other states with lower solar penetration display less marked changes in system load.

Description of Current Rate

HQD provides services to customers with on-site generation under its "Net Metering Option for a Customer Generator". This option is available to both Domestic and Small Power Customers with less than 50 kW peak demand. In months in which the customer's generation exceeds their consumption, the rate provides the customer with a monthly surplus "bank balance" (denominated in kWh) reflecting the excess. In months in which the customer's generation is less than their consumption, the customer uses their bank balance to the extent available, and pays their underlying retail rate for any amount by which the deficit exceeds the bank balance. The customer's surplus does not produce eventual payment by the Company; and the surplus bank balance is set to zero after a finite period no longer than 24 months if it is not used to offset the customer's deficits during that period.

Because customers are billed on their underlying tariff rate, customers' on-site generation is implicitly priced at the HQD energy price that applies to the level of consumption that the generation reduces. A Domestic customer large enough to consume at the tier 2 level reduces its bill at the tier 2 energy price at first, then at the tier 1 price until the net energy consumption equals zero. "Sales" to the utility are only redeemable as future reductions in consumption, and so are valued at the level of consumption that they serve to reduce in a subsequent month. Any kWh left over when the bank balance is set to zero are worthless.

HQD's Design and Industry Practice

DG pricing and rates of other utilities generally operate in a manner very similar to HQD's. That is, rates are generally of the net metering type, in which the customer's net usage for the billing period is recorded by a traditional meter, and the customer is billed according to a variant of the standard tariff. Reductions in (net) consumption reduce the bill at the energy price (or prices in the case of blocked or TOU pricing). If the customer becomes a net seller to the utility (or the grid), they receive either a credit to be set against future bills or a cash payment.

Some utilities manage credit balances by following the "banking" approach that HQD uses and either pay no compensation or a set level of compensation at the end of a contract period, usually one year. However, most utilities establish a price at which the customer can sell excess generation to the utility, usually at a price based on some measure of avoided cost or market value. A few utilities still use the retail tariff price as the sell-back price, but this is a diminishing group. In some highly publicized incidents, regulators have altered this price, sharply reducing it from the utility's retail price of residential service to a measure of avoided cost. This downward revision can significantly lengthen the DG facility cost recovery period of the customer. Among the best-known recent cases was a ruling in late 2015, by the Nevada Public Service Commission.[42] That ruling has since been revised to "grandfather" previous pricing of pre-existing solar units.[43]

Utilities are beginning to explore alternatives to net metering. Discussion of these alternatives appears below following a discussion of rate design issues that challenge DG service generally.

Rate Design Issues and Approaches

DG rates produce several significant pricing and rate design issues, and they are currently being hotly debated. The first issue is the recovery of distribution costs from a DG customer. Distribution facilities are sized to meet the utility's expectation of the customer's non-coincident peak demand because each segment of the distribution system must be able to handle maximum power flows. Under traditional utility tariffs for mass market customers, the costs of distribution facilities are recovered primarily through volumetric (per kWh) charges, which is satisfactory for most customers because their electrical energy consumption is correlated with their peak demands. Net metering breaks the link between the customer's peak demand and their consumption of the utility's electrical energy.

Under net metering, utilities meter and record, with the single meter at the site, net consumption (kWh) for the billing period. The utility then bills the customer according to their net consumption rather than according to their gross consumption, even though it is the latter that is more closely related to the customer's maximum power flows over the distribution system. Net metering thus causes utilities to under-recover distribution costs.

Net metering also has the unwelcome characteristic of depriving utilities of information about customers' gross consumption, information that is important for knowing the customer's needs for distribution infrastructure and for backup generation reserves. One approach to the problem of inadequate data is to install metering, recording, and communication devices that measure gross power consumption and generation flows at the customer's site for the billing period. The utility can then bill the customer for two separate flows, one a debit and one a credit. This "buy-all, sell-all" approach involves an accounting "fiction" that the consumption of the site is provided entirely by the grid while the generation of the site is sold entirely to the

[42] http://fortune.com/2016/04/12/solar-firestorm-nevada/.
[43] http://www.prnewswire.com/news-releases/solarcity-statement-on-nevada-public-utilities-commission-vote-to-grandfather-existing-solar-customers-300329672.html.

grid. In this contractual configuration, the utility charges its standard tariff price for sales (gross site consumption) presumably recovering the full cost of distribution services provided by the utility, and pays for all purchases from the site on the basis of avoided cost. This approach recognizes that avoided cost measures the value of the power that the customer generates, and it has the customer pay their fair share of non-generation costs.

However, this approach is not quite as reflective of cost to serve as might be imagined, since the key to estimating the DG customer's use of the distribution grid is the maximum *net* flow from or to the customer during some recent period, such as a year. This can be measured directly with single-metering of power flow, over very short time intervals (15 minutes or less) accompanied by recording and data management sufficient to record the extreme value(s). This metering approach would price DG services by unbundling energy service from wires services, so that the customer has some version of net metering for energy service while paying for wires services according to maximum power flows to or from the customer site.

The second issue arises from the difficulty of developing a commonly accepted measurement of avoided cost as the basis for pricing energy sold to the utility or the grid. Utilities tend to favor an interpretation of avoided cost that is restricted to actual costs of energy and capacity avoided, which generally amounts to the wholesale market price of energy and reserves (plus capacity perhaps). Advocates of DG see site generation avoiding not only those costs, but also transmission and distribution capacity costs, environmental costs of avoided fossil fuel generation, and other cost elements. The strongest advocates include estimates of net social benefit. The outcome is that the utility and the regulator are confronted with recommendations of avoided cost that can range from $0.05 to $0.15 and perhaps as high as $0.30/kWh US, with the lower end being advocated by utilities and the higher end being advocated by DG supporters.[44]

The third issue pertains to the challenge that tariffs face in reasonably reflecting avoided costs, regardless of how they are measured. Avoided generation costs are generally agreed to be reflected by system marginal cost or, in the case of regional integration, wholesale market energy and reserve services costs, with the inclusion of capacity costs being debated. Avoided generation costs have a time pattern, varying both by season, day of week, and time of day. Flat tariffs, with no time variation in prices, fail to reflect the usual situation in which marginal costs vary over time. Solar DG proponents thus prefer time-varying rates that they expect will have higher prices during the day (when the sun shines) than at night.[45] As another example, blocked rates, like those of California and HQD, must have some blocks with prices that depart significantly from wholesale market price and system marginal cost. Under these conditions, especially if tail block prices are very high, as they are in California, DG can reduce bills at a rate that significantly exceeds marginal cost. For HQD, this may be an emerging problem, given that

[44] See C. Linvill, J. Shenot, and J. Lazar, *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition*, Regulatory Assistance Project, November 2013. Figure 10 contains ranges of Value of Solar studies, with a study average of about $0.15/kWh.

[45] Their enthusiasm for time-varying rates may fade as more and more utilities face power system and cost conditions similar to those of California and Hawaii, as described above.

the utility's proposal is to increase its 2nd tier energy price at a higher rate than its 1st tier price increase.

These issues suggest that long-term viability of DG pricing requires unbundling of charges for energy and wires services, improvements in measurement of avoided costs, use of time- and location-varying DG prices that follow the time and location variations of avoided costs, and improvement in metering and related utility capabilities.

HQD's current rate is consistent with industry practice for those utilities that provide service to a small number of DG customers. As DG penetration increases, however, traditional DG pricing will become less and less viable: net metering prices create incentives for inefficient investment in and dispatch of power sources; and they overcompensate customers for the power that they produce. For the longer term, modifying the tariff to incorporate more efficient pricing and enhanced metering requirements would be beneficial.

Alternative Views on Avoided Costs and Alternative DG Pricing Methods

Solar power proponents have promoted the Value of Solar or, more generally, Value of Resource (VOR) methodology for quantifying avoided costs.[46] This methodology relies on two-meter gross flow measurement at the customer site and the buy-all/sell all billing approach. The VOR methodology advocates valuation methods that have two characteristics that are particularly favorable to solar investments. First, they have supported long-term contracting with the host utility, thus minimizing financial risks for the solar investor while imposing these risks on the utility and its other customers. For most types of avoided cost, the methodology computes a value of avoided cost levelized over the life of the contract, which could be 25 years. While the price of energy may be variable, the avoided costs of generation, transmission and distribution are fixed for the life of the contract, and grow at a predefined rate based on an inflation forecast. The customer obtains assurance of a stream of cash flows that is dependable, which facilitates obtaining project financing. The utility is locked into a fixed-price contract, excluding the avoided cost of energy. The utility might mitigate its risk if it is able to sign a rolling set of numerous but small long-term contracts.

History instructs us that the risks of long-term contracting can be large: the independent power producer contracts that California utilities were forced to sign in the mid-1980s ended up costing them tens of billions of dollars when the long-term fuel price forecasts that served as the basis of the contract prices turned out to be wildly in error. Under VOR, each individual contract is small in size, but accumulating contracts present risks of exposure due to persistent forecast error.

The other characteristic of the VOR methodology that is favorable to solar investments is its inclusion among avoided costs of a number of types of cost that may not actually be avoided,

[46] See *NARUC Manual on Distributed Energy Resources Rate Design and Computation, c. 2016 National Association of Regulatory Utility Commissioners.* Chapter VI. *Rate Design and Compensation: Mechanisms and Methodology* This report provides a discussion of net energy metering, the Value of Resource and other methodologies.

and some that probably are *not* avoided. In other words, the VOR methodology, at least as adopted in Minnesota, tends to inflate avoided costs so that utilities pay to DG resources prices that not only exceed the cash costs that utilities avoid, but also exceed any reasonable estimate of avoided costs that include environmental benefits.[47]

Although the VOR methodology has secured regulatory approval in some jurisdictions, VOR advocates have not been able to develop and compute avoided costs based on their methodologies that have been found persuasive to all parties, especially utilities. There is serious disagreement about the enumeration of the types of avoided cost and about their pricing. For example, DG advocates claim measurable potential avoided distribution cost savings while utilities reject this claim. Rejection stems from two arguments. First, distribution engineers believe that forecasted peak site demands following DG installation are not likely to be much different from those of the site in the absence of DG. In HQD's case, solar power in winter likely does not much diminish peak demands driven by heating load. In summer, solar power is provided to a grid whose transmission constraints may reduce avoided costs to a low level. Second, the introduction of DG systems, especially as penetration increases, complicates power flows and presents uncertain grid management challenges that have not yet been resolved.

For future reference, even more approaches to the computation of value of renewable generation are envisioned.[48] The "Value of Service" concept looks forward to a time when technical advances will enable DG owners to bid the services that their generator might be able to provide into a distribution-level extension of the markets that exist at the transmission level today. In addition to generation services, the owner might be able to offer voltage support, ramping, and even black start services to small segments of the distribution grid. This approach envisions that markets and prices for such services will come into being and that DG owners will be able to develop automated bidding strategies to provide services. An even more ambitious concept, "Transactive Energy" is currently being explored at present. It conceives the possibility of multiparty contracting for energy and grid services, at very detailed local levels. At present, these methods are in the exploratory stage, requiring those who wish to value DG services to consider the currently available alternative methods of valuing avoided cost, and to examine the relative merits of net metering and the buy-all/sell-all approach based on gross metering.

Storage Capability and Distributed Generation

The spread of DG facilities with intermittent weather-dependent power output and the declining cost of electricity storage have combined to create interest the development of storage capability at customer sites. Since the time pattern of supply of DG power, particularly from intermittent resources, cannot easily match the time pattern of loads, storage may be a desirable means of balancing supply and demand, particularly if storage can become cheap

[47] A thorough description of the methodology can be found in *Minnesota Value of Solar: Methodology*, Clean Power Research, 1/31/2014.

[48] See the last portion of Chapter VI of the *NARUC Manual on Distributed Energy Resources Rate Design and Computation* for a description of these alternatives.

enough. In particular, the system ramping concerns illustrated by the duck curve would be significantly reduced if solar power generated during peak daylight hours could be saved and used on-site in the evening hours immediately following.

Electric storage facilities create three kinds of value, all of which can be compensated according to the rules applicable to generators. First, they shift power from periods when power is cheap to periods when power is expensive, "consuming" cheap power and "producing" expensive power. The value of this energy shift equals: a) the quantity of power produced times the power system's high marginal energy cost at the time of production minus b) the quantity of power consumed times the power system's low marginal energy cost at the time of consumption.

The marginal energy cost will be the price of electrical energy in regions with competitive markets. Because of energy losses, the quantity of power produced will always be less than the quantity of power consumed. The owner of a storage facility makes money only if the marginal energy cost (or price) differences among different hours are sufficient to make up for the energy lost in the storage operation.

Second, storage facilities can provide regulation and operating reserves services. Storage owners should be compensated for these services just as generators are compensated. Compensation may be differentiated among generators and storage facilities according to the relatively qualities (like speed or reliability) or the services that they provide.

Third, storage facilities can provide voltage support. Although the compensation should reflect the values of voltage support at the times and places provided, these values cannot be accurately determined. Thus, compensation at cost-of-service-based tariff prices would need to suffice.

For the utility, the pricing challenge is to design rates that neither deter investment in economic storage nor promote investment in uneconomic storage, a challenge that exactly parallels the pricing design challenge for DG itself. As a result, the same design criteria apply: tariffs should be unbundled, particularly between energy and wires services, to permit transparent charges and compensation for the various electricity services, and retail prices should vary with time and by location.

Although net metering is not an obstacle to efficient investment in and use of storage if the net metering applies only to energy services, the banking provisions of net metering tariffs, at HQD and elsewhere, are incompatible with efficient investment in and use of storage. The reason is that banking equalizes the implicit power prices that the DG customer faces over time. Because the main value of storage is in moving power from a low-value period to a higher-value period, banking provisions undermine the incentives for investment in and use of storage.

8. RATES AND COSTS

Use of Embedded and Marginal Costs in Rate Design

Traditional rate design at both vertically integrated utilities and distribution utilities has relied on embedded costs. Embedded costs were selected early in the regulatory era as the proper basis for rate development because they reflect the financial costs of the utility and are relatively stable and free from controversy when compared with other valuation methods. Rate-of-return regulation still makes use predominantly of embedded costs despite the fact that competitive markets are driven by marginal cost.

Some utilities have incorporated marginal cost into aspects of pricing. "Marginal costs" are the change in costs that accompany a change in electricity demand. The relevant costs are those of fuel, variable labor and maintenance, and capacity. In competitive markets, marginal costs can be measured by the prices of electrical energy, ancillary services (like regulating and operating reserves), and capacity. In non-competitive markets, marginal costs are generally quantified for energy and capacity components.

Because the generators that serve demand change over time, marginal costs change over time. Because the generators that can serve changes in demand depend upon the locations of the changes in demand, marginal costs also vary by location.

Hydro-Québec's marginal costs are quite unusual, as mentioned previously. In all but about 300 hours, marginal costs are flat due to the effect of hydraulic dominance and transmission constraints. In remaining hours, in which imports from other jurisdictions are possible, marginal costs may vary, especially at times of low system reserves.

Canadian utilities often use some form of marginal energy (and reserves) cost as the basis for allocating generation and supply costs.[49] Class allocation of such costs can be performed by creating load weighted marginal costs by class or rate and sharing the embedded costs of supply based on those shares.

Additionally, for some time retail pricing practitioners have often used marginal cost for pricing of parts of blocked tariffs and TOU rates, and demand response rates often set prices in high cost periods as a function of day-ahead wholesale market prices. This report has noted several instances in which the use of market-based pricing can facilitate the resolution of rate design debates. Standby and interruptible pricing offer examples.

Utilities have also undertaken marginal cost analyses of transmission and distribution functions, since business decisions require information on the incremental impact on costs of decisions about the grid. A common example involves line extension policies and the allocation or assignment of costs of lines to remote locations.

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[49] For example, Manitoba Hydro uses a weighted energy allocator for generation costs that amounts to marginal energy cost, with time differentiation by season and three time periods.

However, the use of marginal costs entails increasing rate complexity and debate over issues of the methodology of computing marginal cost. The debate over the avoided costs associated with distributed generation is an example of the challenges of what to include in marginal cost.

In its 2016 rate application, HQD filed documentation of its avoided costs, both for its interconnected grid and for isolated systems.[50] The filed document indicates that the interconnected network's avoided costs in the winter are governed by the cost of purchases on the short-term market, including the opportunity to purchase from American markets and Ontario. In summer, avoided cost is the value of water in Hydro-Québec's reservoirs. This is due to the presence of long-standing transmission constraints on exports that exclude the wholesale market prices of other jurisdictions from consideration in avoided cost computation.

HQD's retail prices reflect this seasonality in certain tariffs, as noted previously, especially where a connection to wholesale price is valuable. Marginal cost also is a consideration in Domestic rates, in the 2nd tier price, where that price is maintained above forecasted avoided cost of space heat. The filing records the 2017 avoided cost of space heat as $0.0832/kWh and the tariff request for the 2nd tier is $0.0902/kWh.[51]

The increasing availability of marginal cost information, chiefly from the emergence of wholesale markets offers utilities increasing discretion in the ways to value electric services and the ways to price them. The discussion of rate design issues for most rates reviewed in this report turned up alternative methods of pricing. The review also demonstrated that, in most cases, HQD's rate designs are well within the range of rate designs offered in North America, and that design alternatives are available in case of need.

Rate of Return/Cost Coverage Issues

Rate applications focus considerable energy on rate of return (or the public sector variant, sometimes referred to as cost coverage). Cost of capital experts evaluate the range in which allowed rate of return should lie and regulators select a point estimate, usually within that range as the allowed rate of return. Additionally, utility rate designers and regulators review rate of return or cost coverage by rate class and rate to determine whether customers are paying their fair share of costs. Since the allocation of common costs is at best a task involving approximation and the use of methodologies open to debate, it can be difficult to determine cost responsibility reliably and in a stable manner over successive rate applications.

A common procedure in most jurisdictions is to review revenue-to-cost ratios by rate class and to minimize cross subsidy by exerting steady pressure toward "rate parity." Intervenors ensure that utility and regulatory staff observe this rule. While immediate moves to rate parity seldom occur, due to the resultant sharp increases in certain rates that would ensue, regulators tend to support steady moves in the direction of rate parity, subject to rate stability constraints.

[50] HQD, *Coûts Évités*, R-3980-2016, HQD-4, Document 4, original 2016-7-28.
[51] Avoided cost: *Ibid*, Tableau A-1; Domestic Tier 2 price: *Strategie Tarifaire*, HQD-14, document 2, Original 2016-07-28, Tableau 2.

In Québec, Article 52.1 of the enabling legislation for the Régie appears to have inadvertently imposed rigidity on the process of rate stabilization that occurs in the normal course of regulation in other jurisdictions. HQD documents reveal a rather wide spread in the degree of cost coverage, from a low of 84.8 for Domestic customers in 2015 to a high of 131.2 for Medium Power customers and, more generally, all classes but Domestic are above the benchmark of 100.0.[52]

Other jurisdictions in North America can display similar ranges, but often formal or informal rules press prices into a narrower range. In Canada, most jurisdictions maintain a target "zone of reasonableness" range of plus or minus 5 or 10% around the revenue-to-cost ratio of 1.0 for various rate classes. That is, an index range of plus or minus 10% results in target boundaries of revenue-to-cost ratios of (0.90, 1.10). These targets are regarded as desirable, rather than mandatory, with utilities typically applying to move classes outside the range into the range. In cases of egregious shortfall or excess, movement into the range might occur over multiple rate cases, with limitations in the rate of price change inducing the utility and regulator to agree on a transition plan.

This does not mean that Québec needs to adopt such rules, partly because the ranges are "rules of thumb" rather than values determined by theory or analysis. An indication of how these rules are observed can be gained by reviewing the range of revenue-to-cost ratios, expressed as percentages for several Canadian utilities. The lower end of the range is typically between 80 and 95% and the upper end of the range is between 120 and 135%. The range values have limited implications, though, because often small rate classes like street lighting are responsible for the most extreme values, with revenue-to-cost ratios for major classes being closer to 100%.

Movement by HQD's rate classes toward rate parity (revenue-to-cost ratio of 1.0 or 100%) would ease certain pressures within the jurisdiction. First, business rates could be reduced slightly, and more substantially for Medium Power customer prices. Second, HQD would be less susceptible to accusations of anti-competitive pricing by the natural gas industry if Domestic customer rates were allowed to rise toward parity over a number of years.

The standard objection to raising Domestic prices is that low-income customers will be hurt. However, the limited research available suggests that there is fairly low correlation between income and level of usage. Low customer charges or minimum bills and low Domestic pricing generally tend not to be well-targeted subsidy policy in consequence. Separate measures of account well-being and some form of income-differentiated customer charge (as opposed to a general bill subsidy) appear to be preferable strategies to manage this challenge.[53] Utilities or

[52] HQD, *Stratégie Tarifaire*, HQD-14, document 2, Original 2016-07-28, Tableau 1 (R-3980-2016).

[53] The Rebuttal Testimony of Steven V. Huso, Xcel Energy (Northern States Power Company), Docket No. E002/GR-13-868, July 7, 2014, provides a discussion of that utility's poor correlation between residential usage and income.

their regulators can develop such measure by developing eligibility standards based on information already available from independent sources.[54]

A more serious concern for HQD might be the long-term effect of relative price increases on Domestic class sales, particularly for space heating. However, price response can be expected to occur not just in this class but in other classes in response to prices that would be lower than would otherwise be the case without rate rebalancing in the direction of rate parity. Additionally, exploration of time variation in Domestic rates, beginning with seasonal pricing, might facilitate the spread of electric vehicle charging, a leading area of new sales being considered by other utilities at present.

9. SUMMARY

Appropriateness of HQD's Rate Designs

This review of HQD's tariffs, including comparison with industry practice and a discussion of design theory and issues, has revealed that the utility has rates that conform to industry standards and frequently make use of industry best practices. Most rates are similar in structure to other North American rates. Where departures occur, such as the use of the optimization charge for Large Power customers, there appears to be a clear reason for the departure.

Other utilities may offer greater rate diversity for mass market customers, or different designs for some products (*e.g.* standby rates) but rate deficiencies at HQD are not obvious. In an ideal world, customers might have more tariff options to reflect the diversity of customers' tolerance for price variability and of their cost to serve. However, long standing regulatory tradition advises in favor of uniform treatment of customers, and it is still the case that most regulated utilities have a dominant or "base" rate that serves the vast majority of each major rate class.

Emerging Challenges to Existing Designs

This rate review identifies instances in which changing circumstances may offer new rate design challenges. The first of these is the inadvertent rigidity of revenue-to-cost ratios across rates, leaving some classes underpriced when compared with others. Rate rebalancing constraints appear to be unusually and unnecessarily strong in Québec, restricting HQD's ability to improve pricing over time in line with the principles of cost recovery and price efficiency.

Another challenge is likely to arise from the increasing integration of Québec with other Canadian and American regions. While Québec trades regularly with other regions, and this trade is based on differences in wholesale prices and levels of reserves, the influence of wholesale markets appears not to have fully penetrated retail pricing by the distribution company. Wholesale price differentials may exert influence on rates and may justify the

[54] For example, the CARE program in California utilizes a combination of self-reported income-family size information and residency status data for eligibility.

development of dynamic pricing in certain circumstances. These might include modifications to standby and interruptible pricing, and also the securing of low prices at certain times for customers with competitive alternatives in siting new plant, or in locating production among alternative existing plants.

Electric vehicles offer a Domestic market challenge and opportunity in that the utility does not seem to have a sufficiently time-based rate for the peak winter period to properly signal when it is expensive to charge a vehicle. A voluntary residential TOU rate or a special EV rate with separate metering might be worth review.

Additionally, the development of alternatives to net metering for DG service pricing is worth investigating. If site generation is not yet well established in the province, then the jurisdiction will not be burdened, the way some American jurisdictions are, with customers angry that modifications to the pricing of sales back to the grid have reduced the economic benefits to them of site generation.

As growth in sales slows among Domestic customers, the issue of fixed cost recovery will become more prominent. While some of this is based on the DG challenge, the remainder of the concern lies in the reliance on volumetric rates to recover fixed costs. The customer impact implications of alternative ways to resolve this issue will need careful study.

For business customers, one emerging challenge is how to manage EDR/LRR service requests. HQD carefully restricts access to these pricing schemes, which is sensible. Percentage discounts on bills can distort prices and create impressions of unfairness. Two-part pricing products may assist in this regard by ensuring that the marginal price is shared by all customers while the burden of fixed cost recovery can be customized to some degree in special cases.

Another possible emerging challenge as supply conditions tighten in the future might be the pricing of interruptible load. HQD's rate designs are relatively complicated and may dissuade some categories of customer from participating in these options. The HQD approach does well to attempt to realistically represent load available for interruption. Investigating market-based pricing structures may be productive here in gaining additional curtailment from categories of customer that are not used to being solicited for that type of option.