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Efficient Pricing: The Key to Unlocking Radical Innovation in the Electricity Sector

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Efficient Pricing: The Key to Unlocking Radical Innovation in the Electricity Sector

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Abstract

Innovations in the electricity supply industry will only occur and be adopted if suppliers are compensated for their efforts. In the absence of explicit government support for these activities, innovative technologies and business models will only be adopted only if wholesale and retail prices provide this compensation. Efficient wholesale and retail pricing provides compensation for the cost-effective deployment these innovations. Multi settlement locational marginal pricing markets set efficient short-term wholesale electricity prices. The conventional approach to distribution network pricing is increasingly costly in regions with opportunities to deploy distributed solar generation capacity. Recommendations are provided for improving the efficiency of distribution network pricing. More efficient wholesale and retail pricing implies significantly greater price volatility, particularly as the share of intermittent renewable generation increases, which requires implementing a number of competition and regulatory authority safeguards to protect consumers, while still providing the price signals necessary for consumers adopt beneficial new technologies that will facilitate the least cost transition to significantly more intermittent renewable energy. These safeguards are discussed and rationales for their existence provided.

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1. Introduction

1. To meet their greenhouse gas emissions targets, many countries are forecasting massive increases in utility-scale and distributed renewable generation capacity, primarily utilizing wind and solar resources. This shift to intermittent renewable resources at both ends of the combined transmission and distribution network will require major changes in the planning, operation, and regulation of transmission and distribution networks, the design of wholesale and retail electricity markets, and the regulatory oversight of the entire industry.

2. Much more extensive and sophisticated transmission and distribution networks will be required to manage this intermittency. More sensors must be deployed to improve real time situational awareness throughout the transmission and distribution networks. Software and algorithms must be developed to compile this information and process it to provide signals to controllers embedded throughout the transmission and distribution networks to charge and discharge storage and deploy other devices to maintain a reliable supply of energy and voltage. Both grid-scale and distributed storage devices can to allow renewable energy from high output hours to be consumed during low output hours. Automated demand response technologies can reduce demand during hours with low renewable energy production and shift it to hours with high renewable energy production.

3. These radical changes in the electricity supply industry are unlikely to occur as rapidly or inexpensively as possible without efficient pricing of energy and ancillary services at the wholesale and retail levels. Price signals that reflect the cost of supplying electricity to each location in the transmission and distribution grids during each pricing interval will provide the revenue streams to generation unit owners, electricity retailers, and final consumers that support the investments and ongoing operating costs necessary for this transformation to occur.

4. Particularly as the share of intermittent renewable energy increases, setting spatially and temporally varying prices that reflect the real-time marginal cost of withdrawing energy at each location in the transmission network significantly increases real-time price volatility, which creates challenges for competition authorities and electricity industry regulators. During periods of extremely high and low prices it can be difficult for competition authorities to distinguish between wholesale prices that reflect true supply and demand conditions and those that reflect the exercise of unilateral or coordinated market power.

5. Greater short-term price volatility also increases the potential downside to a market participant from failing to adequately hedge their exposure to short-term prices. Because bankruptcy by one market participant can impose costs on electricity consumers or other market participants, this increased wholesale price volatility implied a greater role for the industry regulator to ensure that no market participant is imprudently exposed to short-term prices.

6. Competition and regulatory authorities must also ensure there are no barriers to consumer choice. Efficient price signals and consumer and producer choice in an industry with low barriers to entry and exit is the most promising approach to a radically lower carbon electricity supply industry. Which automated response devices, storage technologies, and retail pricing plans will deliver the greatest economic benefits to consumers is currently unknown. A level playing field for firms providing these devices, technologies, and pricing plans to compete, with adequate consumer protections in place,

is the best available mechanism for finding the combinations that yield the greatest consumer benefits.

7. The remainder of the paper proceeds as follows. Section 2 describes why efficient pricing requires accounting for all relevant operating constraints in the transmission network and generation unit operation in setting short-term wholesale prices. This is section discusses the role of a multi-settlement locational marginal pricing market in achieving this goal. Section 3 illustrates why the availability of distributed solar photovoltaic (PV) generation capacity has increased the social cost of the historical approach to distribution network pricing. A simple economic model is presented to demonstrate a more efficient approach to distribution network pricing with the availability of distributed solar PV. Section 4 first points why efficient pricing is essential to enabling the radical innovation in the electricity supply industry necessary to maintain a reliable supply of electricity with significant larger share of intermittent renewable generation. The major challenges facing competition and regulatory authorities under efficient wholesale and retail pricing discussed and recommendations for addressing them provided.

2. More Efficient Transmission Network Pricing

8. Thirty years of experience with electricity industry re-structuring provides ample evidence that competition authorities and industry regulators face significant challenges in achieving competitive wholesale market outcomes during vast majority of hours of the year. Virtually all wholesale electricity markets have experienced periods of poor market performance that has required competition or regulatory authority intervention, or at least, resulted in calls for intervention. There is a growing consensus around the world that a short-term wholesale market design that sets prices that reflect all of the costs associated with withdrawing energy at each location in the transmission grid is necessary to prevent these periods of poor wholesale market performance.

2.1. Match Between Market Mechanism and Actual System Operation

9. An important lesson from electricity market design processes around the world is the extent to which the market mechanism used to dispatch and operate generation units is consistent with how the grid is actually operated. In the early stages of electricity restructuring, many regions attempted to operate wholesale markets that used simplified versions of the transmission network. These markets often assumed infinite transmission capacity between locations in the transmission grid or only recognized transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints can create opportunities for market participants to increase their profits by taking advantage of the fact that in real time the actual configuration transmission network and other operating constraints would need to be respected.

10. Many early wholesale electricity markets set a single market-clearing price for a half hour or hour for an entire country or large geographic region despite the fact that there were generation units with offer prices below the market-clearing price not producing electricity and units with offer prices above the market-clearing price producing electricity. This outcome occurs because of the location of demand and available generation units within the region and the configuration of the transmission network prevents some of these low offer-price units from producing electricity and

requires some of the high-offer-price units to supply electricity. The former units are typically called "constrained-off" units and the latter are called "constrained-on" or "must- run" units.

11. A market design challenge arises, because how generation units are compensated for being constrained on or constrained off impacts the offer prices they submit into short-term wholesale energy market. For example, if generation units are paid their offer price for electricity when they are constrained-on and the unit's owner knows that it will be constrained-on, a profit-maximizing unit owner will submit an offer price far in excess of the variable cost of operating the unit and raise the total cost of electricity supplied to final consumers.

12. A similar set of circumstances can arise for constrained off generation units. Constrained-off suppliers are usually paid the difference between the market-clearing price and their offer price for not supplying electricity that it would have supplied if not for the configuration of the transmission network. This market rule creates an incentive for a profit maximizing supplier that knows its unit will be constrained off to submit the lowest possible offer price in order to receive the highest possible payment for being constrained-off and raise the total cost of electricity supplied to final consumers. Bushnell, Hobbs and Wolak (2008) discuss this problem and the market efficiency consequences in the context of the California zonal market. However, it is not unique to industrialized country markets. Wolak (2009) discusses these same issues in the context of the Colombian single-price market.

2.2. Locational Marginal Pricing (LMP)

13. Almost any difference between the market model used to set dispatch levels and market prices and the actual operation of the generation units needed to serve demand creates an opportunity for market participants to take actions that raise their profits at the expense of overall market efficiency. Multi-settlement wholesale electricity markets that use locational marginal pricing (LMP), also referred to as nodal pricing, largely avoid these constrained on and constrained off problems, because all transmission constraints and other relevant operating constraints are respected in the process of determining dispatch levels and prices in the wholesale market.

14. Generation unit owners and load serving entities submit their location-specific willingness-to-supply energy and willingness-to-purchase energy to the wholesale market operator, but locational prices and dispatch levels for generation units at each location in the transmission network are determined by minimizing the as-offered costs of meeting demand at all locations in the transmission network subject to all network operating constraints. No generation unit will be accepted to supply energy if doing so would violate a transmission or other operating constraint.

15. This process sets potentially different prices at all locations in the transmission network, depending on the configuration of the transmission network and geographic location of demand and available generation units. Because the configuration of the transmission network and the location of generation units and demands is taken into account in operating the market, only generation units that can actually operate will be accepted to serve demand and they will be paid a higher price or lower price than the average LMP, depending whether the generation unit is in a generation-deficient or generation-rich region of the transmission network.

16. The nodal price at each location is the increase in the minimized value of the as-offered costs to meet demands at all locations (nodes) in the transmission grid as a result of a one unit increase in the amount of energy withdrawn at that location in the transmission network. Bohn, Caramanis, and Schweppe (1984) provide an accessible discussion of the properties of this market mechanism.

17. Another strength of the LMP market design is the fact that other constraints that the system operator takes into account in operating the transmission network can also be accounted for in setting locational prices and dispatch levels. For example, suppose that reliability studies have shown that a minimum amount of energy must be produced by a group generation units located in a small region of the grid. This operating constraint can be built into the market-clearing mechanism and reflected in the resulting LMPs. This property of the LMP markets is particularly relevant to the cost-effective integration a significant amount of intermittent renewable generation capacity. Additional reliability constraints may need to be formulated and incorporated into LMP market to account for the fact that this energy supply can quickly disappear and re-appear.

18. An important implication of modelling all relevant operating constraints in setting LMPS is that in order to withdrawal one more unit of energy at location in a particularly constrained region of the grid can require backing down generation units or demands at other locations in the grid, all which can increase the LMP at that location. Consequently, an under-appreciated implication of LMP pricing is that price at these locations can be multiples of the maximum allowed offer price in the wholesale market. For example, in LMP markets with $1,000/MWh caps on a generation unit owner offers, LMPs of $5,000/MWh have been observed during heavily constrained time periods. As more intermittent renewables are added to the generation mix, the potential is even greater for these system conditions to arise and extremely high and low LMPs to occur.

2.3. Multi-Settlement Markets

19. Multi-settlement nodal-pricing markets have been adopted by all US jurisdictions with a formal short-term wholesale electricity market. A multi-settlement market has a day ahead forward market that is run in advance of real-time system operation. This market sets firm financial schedules for all generation units and loads for all 24 hours of the following day. Suppliers submit generation unit-level offer curves for each hour of the following day and electricity retailers submit demand curves for each hour of the following day. The system operator then minimizes the as-offered cost to meet these demands for all 24 hours of the following day subject to the anticipated configuration of the transmission network and other relevant operating constraints during all 24 hours of the following day. This gives rise to LMPs and firm financial commitments to buy and sell electricity each hour of the following day for all generation unit and load locations.

20. These day-ahead commitments do not require a generation unit to supply the amount sold in the day-ahead market or a load to consume the amount purchased in the day-ahead market. The only requirement is that any shortfall in a day-ahead commitment to supply energy much be purchased from the real-time market at that same location or any production greater than the day-ahead commitment is sold at the real-time price at that same location. For loads, the same logic applies. Additional consumption beyond the load's day-ahead purchase is paid for at the real- time price at that location and the surplus of a day-ahead purchase relative to actual consumption is sold at the real-time price at that location.

21. In all US wholesale markets, real-time LMPs are determined from the real-time offer curves from all available generation units and dispatchable loads by minimizing the as offered cost to meet real-time demand at all locations in the control area taking into account the current configuration of the transmission network and other relevant operating constraints. This process gives rise to LMPs at all locations in the transmission network and actual hourly operating levels for all generation units. Real-time imbalances relative to day ahead schedules are cleared at these real-time prices.

22. To understand how a two-settlement market works, suppose that a generation unit owner sells 50 MWh in the day-ahead market at $60/MWh. It receives a guaranteed $3 000 in revenues from this sale. However, if the generation unit owner fails to inject 50 MWh of energy into grid during that hour of the following day, it must purchase the energy it fails to inject at the real-time price at that location. Suppose that the real-time price at that location is $70/MWh and generator only injects 40/MWh of energy during the hour in question. In this case, the unit owner must purchase the 10 MWh shortfall at $70/MWh. Consequently, the net revenues the generation unit owner earns from selling 50 MWh in the day-ahead market and only injecting 40/MWh is $2 300, the $3 000 of revenues earned in the day-ahead market less the $700 paid for the 10 MWh real-time deviation from the unit's day-ahead schedule.

23. If a generation unit produces more output than its day-ahead schedule, then this incremental output is sold in the real-time market. For example, if the unit produced 55 MWh, then the additional 5 MWh beyond the unit owner's day-ahead schedule is sold at the real-time price. By the same logic, a load-serving entity that buys 100 MWh in the day ahead market but only withdraws 90 MWh in real-time, sells the 10 MWh not consumed at the real-time price. Alternatively, if the load-serving entity consumes 110 MWh, then the additional 10 MWh not purchased in the day-ahead market must be purchased at the real time price.

24. A multi-settlement LMP market design is also particularly well-suited to managing a generation mix with a significant share of intermittent renewable resources. The additional operating constraints necessary for reliable system operation with an increased amount of renewable resources can easily be incorporated into the day-ahead and real-time market models. Therefore, the economic benefits from implementing a multi-settlement LMP market relative to market designs that do not model all transmission and other operating constraint are likely to be greater the larger is the share of intermittent renewable resources because of the increasing number of operating constraints that must be accounted for in both system and market operation.

25. A multi-settlement LMP market also values of the dispatchability of generation units even though it pays all resources at the same location in the grid the same price in the day-ahead and real-time markets. Suppose that a wind unit sells 50 MWh and a thermal resource sells 40 MWh in the day-ahead market at $30/MWh. If in real-time, not as much wind energy is produced, the dispatchable thermal unit must make up the difference. Suppose that the wind unit produces only 30 MWh, so that the thermal unit must produce an additional 20 MWh. Because of this wind generation shortfall, the real-time price is now $60/MWh. Under this scenario, the wind unit is paid an average price of $10/MWh = (50 MWh x $30/MWh – 20 MWh x $60/MWh)/30 MWh for the 30 MWh it produces, whereas the dispatchable thermal unit is paid an average price of $40/MWh = (40 MWh x $30/MWh + 20 MWh x $60/MWh)/60 MWh for the 60 MWh it produces. Similar logic applies to the case that the wind resource produces more than expected and the thermal resource reduces its output because the real-time price is lower

than the day-ahead price because of the unexpectedly large amount of wind energy produced. Consequently, multi-settlement markets benefit intermittent resource owners that are better able to forecast, on a day-ahead basis, the real-time production of their generation units.

26. One complaint often leveled against LMP markets is that they increase the likelihood of political backlash from consumers because prices paid for wholesale electricity can differ significantly across locations within the same geographic region. For example, customers in urban areas that primarily import electricity over congested transmission lines will pay more than customers located in generation-rich rural regions that export electricity to these regions. Because more customers live in the urban areas than in the rural regions charging final consumers in the urban areas a higher retail price to recover the LMP at their location may be politically challenging for the regulator to implement.

27. Many regions with LMP pricing have overcome this potential problem by charging all customers in a given state or utility service territory a weighted average of the LMPs in the region. In the above example, this implies charging the urban and rural customers the weighted average of the LMPs in the urban and rural areas, where the weight assigned to each price is the share of system load that is withdrawn at that location. Under this scheme, generation units continue to be paid the LMP at their location. For example, in Singapore all generation units are paid the LMP at their location, but all loads are charged the Uniform Singapore Electricity Price (USEP), which is the quantity-weighted average of the half hourly LMPs for all load-withdrawal points in Singapore. This approach to pricing captures that reliability and operating efficiency benefits of an LMP market while addressing the equity concerns regulators often face with charging customers at different locations prices that reflect the configuration of the transmission network.

28. The experience of all US wholesale electricity markets supports the argument that a multi-settlement LMP market design is most effective mechanism for achieving economically efficient wholesale prices. All US wholesale markets initially used simplified models of the grid in the dispatch of generation units and pricing of energy. These designs created significant market performance problems, particularly in regions with limited transmission capacity. As a result, all these regions ultimately adopted multi-settlement LMP market designs.

3. More Efficient Distribution Network Pricing

29. Because there were no financially viable substitutes for grid-supplied electricity, the traditional approach to the distribution network pricing of a fixed per-unit charge for all withdrawals distribution grid introduced a limited amount of economic inefficiencies. Charging a per unit price for use of the distribution grid that is higher that the marginal cost of withdrawing energy from the grid increases the per-unit retail price, but any reduction in the per unit distribution charge would have to be recovered from a higher monthly fixed charge in order for the distribution network owner to recover the sunk costs of the grid.

30. When a customer has the option to install distributed solar capacity pricing the distribution network and other non-volume variable costs on a per-unit basis can introduce two significant distortions. First, a customer considering a distributed solar PV unit compares the levelized cost of electricity from this facility to the average per unit

retail price, not the average wholesale price implicit in the retail price it faces. Second, the customers that install distributed solar now consume significantly less grid-supplied energy, but the sunk costs of the grid remain the same. This means that the per unit distribution price must be increased for all customers, which encourages more customers to install distributed solar.

3.1. Inefficient Bypass of Grid-Supplied Electricity

31. Each hour of the day there is a marginal cost of withdrawing an additional unit of electricity from any location in transmission grid. In regions with formal wholesale electricity markets, this is equal to real-time locational marginal price at that location. Adding the marginal cost of losses between the point withdrawal from the transmission grid to the customer's distribution grid and the customer's premises, yields the marginal cost of supplying that customer with an additional KWh of grid-supplied electricity during that hour.

32. Because the current retail tariff recovers the vast majority of the cost of the transmission and distribution grid in the per unit price, during the vast majority of hours of the year the fixed price charged for grid-supplied electricity is vastly in excess of marginal cost supplying the customer with an additional KWh of grid-supplied electricity during that hour. To take the example of Pacific Gas and Electric in California, until very recently a residential customer consuming on the highest step of the increasing block price schedule paid a marginal price of 36 cents/KWh for grid-supplied electricity that typically sold in the short-term for between 3 and 4 cents/KWh.

33. The tremendous volatility in the hourly price of wholesale power that is likely to occur with significant amounts of intermittent renewables can induce significant inefficiencies in consumption of electricity relative to a retail pricing plan that sets the hourly marginal cost of grid-supplied electricity equal to the marginal retail price. Paying a price that is more than nine times the price paid for grid-supplied electricity is likely to lead to under-consumption relative to the efficient. This set of circumstances is not unusual for virtually all electricity retailers in regions with significant amounts of intermittent renewable resources.

34. If the levelized cost of energy (net of any government support to the consumer) from a distributed solar PV system is less than the cost to the consumer of purchasing this electricity from the grid under the current retail tariff, the customer will find it privately cost-effective to install a distributed solar system. However, if the average incremental cost of providing this customer with the electricity produced by its distributed solar system is less than incremental cost of obtaining this energy from the grid, then cost of supplying the customer with energy has risen as a result installing the distributed solar system and the customer has made a socially inefficient investment in a distributed solar system (even excluding the cost of the government support).

35. A numerical example based on Pacific Gas and Electric illustrates this point. Suppose the levelized cost of a solar PV system net of the government support is 25 cents/KWh and the customer typically ended on month consuming on the 36 cents/KWh step of the nonlinear price schedule before installing a solar system. Suppose the average wholesale price for energy is 4 cents/KWh. Although the customer is saving 11 cents/KWh from investing in a solar PV system that reduces consumption on the 36 cents/KWh step to zero, the average total cost of supplying him with energy increased by 21 cents/KWh as a result of investing in the distributed solar system.

3.2. Toward More Efficient Retail Pricing

36. This section presents an economic model that illustrates several pathways for improving the efficiency of retail electricity pricing. I first consider the case that customers have meters that can record their consumption on an hourly basis, to match the frequency that the marginal cost of retail electricity changes. Then I consider the case of customers with mechanical meters that can only record their monthly consumption.

37. Let C(h) equal the marginal cost of retail electricity facing the customer during hour of the year h, for h=1,2,…,H, where H is the total number of hours in the year. To a first approximation, C(h) is equal to the hourly wholesale price at the customer's distribution network location times the marginal distribution loss factor for delivery to his premises. Define the customer's hourly demand curve for electricity to be Q(h) = A(h) – P(h). A(h) is the customer's willingness to pay for the first unit of consumption. Suppose that both C(h) and A(h) are random variables with compact support and a joint density, F(C,A). The support of C(h) is [CL,CH] and [AL,AH] where $0 < CL < CH < \infty$, $0 < AL < AH < \infty$, and AL > CH. The last inequality imposes the reasonable assumption that it is socially optimal for the customer to always consume a non-zero amount of electricity.

38. Economically efficient pricing implies that the hourly retail price of electricity should be set equal to the hourly marginal cost of grid supplied electricity, so that P(h) = C(h). Using the logic of two-part tariff pricing, the maximum fixed charge that the consumer can pay for grid- supplied electricity during this hour is the area below the demand curve above the hourly price. This is the shaded area in Figure 1 and is equal ½(A(h) – C(h))2.

39. Suppose before setting the fixed charge for the year or month, that the regulator only knows that the (A(h),C(h))′ are independent, identically distributed draws across the H hours of the year. Figure 2 shows the value of hourly consumer surplus (CS) for the extreme case of when A(h) = AL and C(h) = P(h) = CH, and the hourly value of consumer surplus is extremely small. Figure 3 shows the other extreme of A(h) = AH and C(h) = P(h) = CL, and the hourly value of consumer surplus is extremely large.

40. Suppose that the consumer is risk neutral with respect to his electricity consuming decisions and will remain connected to the grid for the year if the expected annual fixed charge is less than the expected value of the annual consumer obtained from consuming at P(h) = C(h) each hour of the year. Taking the expected value of ½(A(h) – C(h))2, yields the following result:

Annual Expected CS = ½ [Var(A(h)) – 2(Cov(A(h),C(h))) + Var(C(h))] + [E(A(h)) - E(C(h))]2H.

41. This expression provides guidance for setting the value of the fixed charge for each customer. We expect that different customer to have different distributions of A(h) and different distributions of C(h), depending on the location of their distribution network and the location of their premises in the distribution network. For each customer their annual fixed charge cannot exceed the Annual Expected CS given above, or they would disconnect from the grid.

42. This expression implies that customers with a large variance in their demands and large variance in the marginal cost of supply should pay higher fixed charges. Customers with a larger expected consumption, [E(A(h)) – E(C(h))] should also pay higher fixed charges. Customers with demands that are more highly correlated with the marginal cost of grid supplied electricity should pay lower prices. Because higher wholesale prices tend to occur in high system demand periods, one interpretation of this result is that customers

whose demands are more highly correlated with the system demand should pay lower fixed charges.

43. Although this simple model does not specify the absolute magnitude of fixed charges for each customer, it does provide clear guidance for setting relative values of these fixed charges across customers. High demand customers, with volatile demand facing volatile prices at their locations that are negatively correlated with wholesale prices should pay the highest fixed charges. Low demand customers, with stable demands, facing relatively stable hourly prices that are positively correlated with their

44. For the case that the customer only has a mechanical meter, suppose the customer can only be charged a price for their consumption each hour equal to expected marginal cost E(C(h)) of grid-supplied electricity. Under these conditions, the hourly value of consumer surplus is equal to ½(A(h) – E[C(h)])2. Following the above logic yields the following expression:

$$\text{Annual Expected CS} = ½\ [\mathrm{Var}(A(h)) + [E(A(h) - E(C(h))]2H.$$

45. This expression yields several insights. First, depending on the values of Cov(A(h),C(h)) and Var(C(h)), the maximum fixed charge could be larger or smaller for a customer with an interval meter relative to one with the mechanical meter. If the customer's demands are uncorrelated with hourly marginal cost of grid-supplied electricity, then having an interval meter and paying according to C(h) instead of E(C(h)) implies that the customer should be willing to pay a higher fixed charge.

46. The second result is the clear prediction that customers with higher expected demand and greater volatility in their hourly demand have should face higher fixed charges. Finally, for customers with mechanical meters paying for grid-supplied energy at E(C(h)) each hour, should not pay different fixed charges prices depending on the volatility of marginal cost of producing them with electricity.

47. In both cases, charging for retail electricity using this tariff should significantly reduce the incentive for customers to engage in inefficient bypass, because they will only invest is distributed solar if it is socially efficient for them to do so.

48. This analysis yields two basic recommendations for more efficient distribution network pricing. First, the per-unit charge should only reflect the marginal cost of withdrawing energy from the distribution grid at the customer's location during each hour of the day. This will produce a substantial smaller per-unit charge than is currently the case. Second, because distribution pricing is fundamentally a sunk cost recovery problem, the burden of paying for these sunk costs should be allocated based on the willingness to pay of customers without causing disconnection of any customer from the electricity delivery network.

4. Consumer-Friendly Innovation in the Electricity Sector

49. Prices that reflect anticipated or actual real-time conditions in the transmission and distribution grid during each hour of the day at each location provides economically efficient signals for storage devices, automated response technologies, and sensors and control system that can reduce the cost of serving demand at all locations in the grid. Investments in storage, automated response technologies and sensors and control systems are financially viable because they enable the owner profit from the price swings caused by the intermittency of renewable production. Consequently, spatial and temporal price

volatility that reflects local supply and demand conditions facilitates the least cost deployment of these new technologies.

50. This potential for wholesale price volatility has the downside that it is challenging for the competition and/or regulatory authority to determine if the reason for extreme prices is supply and demand conditions or the exercise of unilateral or coordinated market power. For this reason a number of regulatory safeguards are necessary to ensure that customers realize the maximum economic benefits for the least risk from more efficient pricing of electricity.

51. First is a mechanism for managing and mitigating system-wide and local market power. Second is appropriate safeguards for retailers and consumers against excessive exposure to short- term wholesale prices. Third is eliminating barriers to consumer choice. With these regulatory safeguards in place, more efficient pricing across space and over time is likely to deliver the greatest benefits to electricity consumers.

4.1. Managing and Mitigating System-wide and Local Market Power

52. The configuration of the transmission network, the level and location of demand, as well as the level of output of other generation units can endow certain generation units with a significant ability to exercise unilateral market power. A prime example of this phenomenon is the constrained-on generation problem described earlier. The owner of a constrained-on generation unit knows that regardless of the unit's offer price, it must be accepted to supply energy. Without a local market power mitigation mechanism, there is no limit to what offer price that supplier could submit and be accepted to provide energy.

53. The system-wide market power problem is typically addressed through sufficient fixed- price and fixed-quantity long term contracts between suppliers and electricity retailers and large consumers. As discussed in Wolak (2000) and McRae and Wolak (2012), fixed price forward contract obligations limit the incentive of suppliers to exercise system-wide unilateral market power in the short-term market.

4.1.1. Solutions to the Local Market Power Problem

54. There are a variety of regulatory mechanisms that exist around the world to address the local market power problem. In an offer-based market, the regulator must design and implement a local market power mitigation mechanism. In general, the regulator must determine when any type of market outcome causes enough harm to some market participants to merit explicit regulatory intervention. Finally, if the market outcomes become too harmful, the regulator must have the ability to temporarily suspend market operations. All of these tasks require a substantia l amount of subjective judgment on the part of the regulatory process.

55. In all offer-based electricity markets a local market power mitigation (LMPM) mechanism is necessary to limit the offers a supplier submits when it faces is insufficient competition to serve a local energy need because of combination of the configuration of the transmission network and concentration of ownership of generation units. As the share of intermittent renewable resources grows, the need for an LMPM mechanism increases, because the market operator must account for more reliability constraints in the dispatch process, which creates more opportunities for dispatchable generation units to exercise local market power.

56. A LMPM mechanism is a pre-specified administrative procedure (usually written into the market rules) that determines: (i) when a supplier has local market power worthy of mitigation; (ii) what the mitigated supplier will be paid; and (iii) how the amount the supplier is paid will impact the payments received by other market participants. Without a prospective market power mitigation mechanism system conditions are likely to arise in all wholesale markets when almost any supplier can exercise substantial unilateral market power. It is increasingly clear to regulators around the world, particularly those that oversee markets with a significant amount of intermit tent renewable generation capacity, that formal regulatory mechanisms are necessary to deal with the problem of insufficient competition to serve certain local energy needs.

57. An important component of any local and system-wide market power mitigation mechanism is the provision of information to market participants and public at large, is often termed, "smart sunshine regulation." This means that the regulatory process gathers a comprehensive set of information about market outcomes, analyzes it, and make it available to the public in a manner and form that ensures compliance with all market rules and allows the regulatory and political process to detect and correct market design flaws in a timely manner. Smart sunshine regulation is the foundation for all of the tasks the regulatory process must undertake in the wholesale market regime. Wolak (2014) discusses the benefits of smart sunshine regulation and public data release on wholesale market performance.

58. Another regulatory tool for managing local and system-wide market power in an offer- based market is the configuration of the transmission network, which can determine the extent of competition that individual suppliers face in the short-term market. For this reason, the regulator must take a more active role in the transmission planning and expansion process, particularly as the share of intermittent renewables increases, to ensure that competition-enhancing upgrades that improve market performance are built. Wolak (2015) presents a framework for measuring the competitiveness benefits of transmission expansions in an offer-based wholesale market and applies it to the Alberta, Canada wholesale electricity market.

4.1.2. Cost-Based Short-Term Markets

59. An alternative approach to limiting system-wide and local market power used in a number of Latin American markets is a cost-based market. Under this mechanism generation unit owners do not submit offers to the market operator. Instead the market operator takes the technical characteristics of generation units and input fuel prices to compute the variable cost of operating each generation unit. These variable cost estimates are used by the market operator to dispatch generation units and set market prices, which are typically equal to the highest variable cost necessary to meet demand. Galetovic, Munoz, and Wolak (2015) describe the operation of the cost-based market in Chile.

60. This mechanism avoids the need for a local market power mitigation mechanism, but is not without its challenges. For example, it does not completely close off opportunities for suppliers to exercise unilateral market power because they can still withhold their output from the cost-based dispatch as a way to increase short-term prices. They can also take actions to raise their regulated variable cost that enters the cost-based dispatch process. Wolak (2014) discusses the market efficiency trade-offs between offer-based versus cost-based markets.

4.2. Protecting Consumers from Economic Harm

61. The likely increase in short-term wholesale price volatility that will fund investments in storage, automated response technologies, and sensor and control systems also has the potential to cause significant financial harm to electricity consumers. This suggests a role for number of regulatory safeguards to protect consumers such as: (i) monitoring retailer hedging activity to ensure that they are not imprudently exposed to short-term prices; and (ii) providing the necessary technology, information and retail pricing plans to provide consumers with low-risk ways to participate in the wholesale market.

4.2.1. Monitoring Forward Contract Positions of Retailers

62. As noted above, fixed-price forward contract commitments sold by generation unit owners reduce their incentive to exercise unilateral market power in the short-term energy market because the supplier only earns the short-term price on any energy it sells in excess of its forward contract commitment and pays the short-term price for any production shortfall relative to these forward contract commitments. Consequently, fixed-price forward contracts also provide the buyer and seller of a contract with protection against short-term price risk for the quantity of energy traded in the forward contract.

63. Because short-term wholesale prices are likely to become more volatile with a larger renewable energy share, this role for fixed-price forward contracts is likely to become even more important. Moreover, because the failure of a retailer to adequately hedge their exposure to short-term prices can impose costs on all of its customers as well as the customers of other retailers if it goes bankrupt, there is regulatory rationale for ensuring that retailers are not imprudently exposed to short-term wholesale price risk.

64. This logic argues in favor of the regulator monitoring the forward contract positions of retailers as part of its regulatory oversight process to ensure that there is adequate fixed-price forward contract coverage of final demand. As discussed in Wolak (2003b) and reinforced by the simulation results of Bushnell, Mansur and Saravia (2008), the California electricity crisis is very unlikely to have occurred if there had been adequate coverage of California's retail electricity demand with fixed-price and fixed-quantity forward contracts. High levels of fixed-price forward contract coverage of final demand would have protected retailers selling to final consumers at a fixed price from having purchase significant amounts of energy in the short-term market at extremely high and prices, which eventually caused at least one large retailer to declare bankruptcy.

65. The regulatory process would require retailers to make regular filings of the their fixed-price retail load obligations and the fixed-price forward contracts they have to hedge the wholesale price risk associated with serving these fixed-price retail load obligations. To the extent that final consumers are willing to manage short-term price risk through dynamic pricing plans for some their hourly demand, retailers can reduce their fixed-price forward contract purchases.

4.2.2. Active Involvement of Final Demand in the Wholesale Market

66. The active involvement of final consumers in the wholesale market can reduce the amount of installed generation capacity needed to serve them and can reduce the cost of integrating an increasing amount of intermittent renewable generation. An important market design feature that facilitates active participation by final demand is a

multi-settlement market with a day-ahead forward market and real-time market. This mechanism allows loads to purchase energy in the day-ahead market that they can subsequently sell in the real-time market. Without the ability to purchase demand in the day-ahead market that is not consumed in real-time, demand reduction programs require the regulator to set an administrative baseline, which can significantly reduce the system-wide benefits of active demand-side participation. This issue is discussed in Bushnell, Hobbs, and Wolak (2009).

4.2.3. Informed Customers with Interval Meters Can Respond to Dynamic Retail Prices

67. There are three necessary conditions for active involvement of final consumers. First, customers must have the necessary technology to record their consumption on an hourly basis. Second, they must receive actionable information that tells them when to alter their consumption.[1] Third, they must pay according to a price that provides an economic incentive consistent with actionable information to alter their consumption. A major challenge to active involvement of final consumers in the wholesale market is the availability of the technology to record the customer's consumption on an hourly basis.

68. There is growing empirical evidence that all classes of customers can respond to short-term wholesale price signals if they have the metering technology to do so. Patrick and Wolak (1999) estimate the price-responsiveness of large industrial and commercial customers in the United Kingdom to half-hourly wholesale prices and find significant differences in the average half- hourly demand elasticities across types of customers and half-hours of the day. Wolak (2006) estimates the price-responsiveness of residential customers to a form of real-time pricing that shares the risk of responding to hourly prices between the retailer and the final customer. The California Statewide Pricing Pilot (SPP) selected samples of residential, commercial, and industrial customers and subjected them to various forms of real-time pricing plans in order to estimate their price responsiveness. Charles River Associates (2004) analyzed the results of the SPP experiments and found precisely estimated price responses for all three types of customers. More recently, Wolak (2011a) reports on the results of a field experiment comparing the price- responsiveness of households on a variety of dynamic pricing plans. For all of pricing plans, Wolak found large demand reductions in response to increases in hourly retail electricity prices across all income classes.

69. Although all of these studies find statistically significant demand reductions in response various forms of short-term price signals, none are able to assess the long-run impacts of requiring customers to manage short-time wholesale price risk. Wolak (2013) describes the increasing range of technologies available to increase the responsiveness of a customer to short-term price signals. However, customers have little incentive to adopt these technologies unless regulators are willing to install hourly meters and require customers to manage short-term price risk.

4.2.4. Managing Bill Risk with Dynamic Pricing

70. Politicians and policymakers often express the concern that the subjecting consumers to real-time price risk will introduce too much volatility into their monthly bill. These concerns are, for the most part, unfounded as well as misplaced. Wolak (2013)

[1] McRae and Meeks (2016) presents the results of a field experiment in Central Asia that demonstrates the importance of actionable information for facilitating active demand-side participation.

suggests a scheme for facing a consumer with the hourly wholesale price for her consumption above or below a pre-determined load shape so that the consumer faces a monthly average price risk similar to a peak/off-peak time- of-use tariff.

71. It is important emphasize that if a state regulatory commission sets a fixed retail price or fixed pattern of retail prices throughout the day (time-of-use prices), it must still ensure that the over the course of the month or year, the retailer's total revenues less its transmission, distribution and retailing costs, must cover its total wholesale energy costs. If the regulator sets this fixed price too low relative to the current wholesale price then either the retailer or the government must pay the difference.

72. Charging final consumers the same hourly default price as generation units owners, provides strong incentive for them to become active participants in the wholesale market or purchase the appropriate short-term price hedging instruments from retailers to eliminate their exposure to short-term price risk. These purchases of short-term price hedging instruments by final consumers increases the retailer's demand for fixed-price forward contracts from generation unit owners, which reduces the amount of energy that is actually sold at the short-term wholesale price.

4.2.5. Fostering Investments in Automated Response Technologies

73. Perhaps the most important, but most often ignored, lesson from electricity re-structuring processes in industrialized countries is the necessity of treating load and generation symmetrically. Symmetric treatment of load and generation means that unless a retail consumer signs a forward contract with an electricity retailer, the default wholesale price the consumer pays is the hourly wholesale price. This is precisely the same risk that a generation unit owner faces unless it has signed a fixed-price forward contract with a load-serving entity or some other market participant. The default price it receives for any short-term energy sales is the hourly short-term price. Just as very few suppliers are willing to risk selling all of their output in the short-term market, consumers should have similar preferences against too much reliance on the short-term market and would therefore be willing to sign a long-term contract for a large fraction of their expected hourly consumption during each hour of the month.

74. Consistent with the above logic, a residential consumer might purchase a right to buy a fixed load shape for each day at a fixed price for the next 12 months. This consumer would then be able to sell energy it does not consume during any hour at the hourly wholesale price or purchase any power it needs beyond this baseline level at that same price.[2] This type of pricing arrangement would result in a significantly less volatile monthly electricity bill than if the consumer made all of his purchases at the hourly wholesale price. If all customers purchased according to this sort of pricing plan then there would be no residual short-term price risk that the government needs to manage using tax revenues. All consumers manage the risk of high wholesale prices and supply shortfalls according to their preferences for taking on short-term price risk. Moreover, because all consumers have an incentive to reduce their consumption during high- priced periods, wholesale prices are likely to be less volatile. Symmetric treatment of load and

[2] Wolak (2013) draws analogy between this pricing plan for electricity and how cellphone minutes are typically sold. Consumers purchase a fixed number of minutes per month and typically companies allow customers to rollover unused minutes to the next month or purchase additional minutes beyond these advance-purchase minutes at some penalty price. In the case of electricity, the price for unused KWhs and additional KWhs during a given hour is the real-time wholesale price.

generation does not mean that a consumer is prohibited from purchasing a fixed-price full requirements contract for all of the electricity they might consume in a month, only that the consumer must pay the full cost of the retailer supplying this product.

75. The risk of paying the real-time price for their electricity is what creates the business case for investments automated response technologies and storage technologies. If the customer can avoid consumption when the real-time price is high and consume more when the price is low, through an investment in one of these devices, they are very likely to do so if the wholesale energy purchase costs this technology avoids more than covers the cost of this investment. A single fixed retail price or single fixed price schedule regardless of real-time system conditions can never provide the revenue stream needed to finance investments in these technologies. Consequently, without exposing customers to the risk of the real-time price in the same way that generation unit owners face this price as their default price for electricity sales, investments in these technologies will not occur without explicit support mechanisms.

4.3. Customer Choice

Customer choice is a crucial driver of the adoption of new technologies in the electricity sector. Efficient pricing without market participants having the freedom to respond to these economic signals will not produce the intended economic benefits to consumers. There are a number of competition and regulatory policies that facilitate customer choice. These are: (i) interval meters to record a customer's half-hourly or hourly consumption; (ii) the ability of customers to share their consumption data with competitive energy service providers; (iii) actionable information about available technologies and pricing plans; and (iv) clearly specified default provider obligations.

4.3.1. Interval Meters

75. In order to set the dynamic retail prices that provide the business case for investments in storage, load-shifting and control technologies, customers must have interval meters. Without the ability to measure a customer's consumption within a pricing interval, it is impossible to provide the full economic benefits to the customer from shifting their consumption into or away from that time interval.

76. With mechanical meters it is only possible to measure at customer's consumption between two meter readings. As discussed in Wolak (2013), with monthly reading of a mechanical meter, the customer's monthly bill is reduced by the same amount of regardless of which hour in the month the customer reduces consumption.

77. Consequently, in order to unlock the full economic benefits of efficient pricing, all customers must have interval meters. In most industrialized countries this has been accomplished by making meter deployment and reading a regulated service provided by the distribution utility. Given the substantial economic benefits of that these meters enable, the declining cost of these meters and the need to eventually replace all mechanical meters, this approach offers customers the maximum flexibility to participate in the wholesale market.

78. It important to emphasize that installing meters that simply record consumption at a 15-minute level or finer level of temporal granularity is sufficient to accomplish this task. There is little need for meters with enhancements beyond these basic functions to be part of a regulated distribution service. Enhancements to this basic service can be provided by third-party energy service firms.

4.3.2. Sharing Customer Data

79. In order for retailers to compete for customers they must have information on the load shape of the customer. A customer with a daily load shape that is highest during low-priced hours of the day is cheaper to serve than one with a load shape that is highest during the high-priced hours of the day. The most straightforward approach to addressing this issue is to allow customers to opt into providing their historical hourly consumption data to competing retailers and other third-parties.

80. An alternative approach would be to provide all data in an anonymized manner to all potential retailers and demand-response providers and then allow the retailer to solicit customers based on their permission to be contacted. It is important to recognize that without granting third- party access to a customer's data, the diffusion of new storage, load-shifting and control technologies will likely be slowed as well as more costly.

4.3.3. Actionable Information

81. Under retail competition, the price-setting function of the regulator is no longer relevant. However, this does not mean that the regulator should no longer protect consumers from the exercise of market power. Instead, the regulator must now transition to assisting consumers with becoming more able market participants.

82. Regulators should inform customers of what is likely to be lowest cost retail pricing plan for them through a web-site or other customer engagement mechanism. Similar information could be provided about new storage, load shifting and control technologies that could be benefit the consumer. The regulatory could serve as the "honest broker" in introducing these technologies to electricity consumers by providing informational web-sites that assist them in deciding whether investments in these technologies make economic sense.

4.3.4. Default Provider Obligation

83. The regulator must set clear rules for determining the default provider obligation. Specifically, what is the retail price that a customer must pay if their retailer goes bankrupt or exits the industry. During the early stages of retail competition, when more entry and exit is likely to occur, it is important to have clear rules for determining this default provider obligation.

84. As retail competition matures, there is less need for a formal regulatory process to address this issue. If a customer's retailer exits, there should may competitors willing to provide service at a reasonable price.

5. Conclusions

85. This paper argues that efficient pricing at the wholesale and retail level is a key driver of innovation in an electricity supply industry with significant intermittent renewable energy goals. Multi-settlement locational marginal pricing markets are the consensus choice internationally for a market design that sets efficient short-term wholesale electricity prices. The cost of not adopting the most efficient wholesale pricing mechanism are likely to increase at the share of intermit tent renewables increases.

86. The conventional approach to distribution network pricing is increasingly costly in regions where distributed solar PV can be easily deployed. Two suggestions are provided for improving the efficiency of distribution network pricing.

87. Efficient wholesale and retail pricing implies significantly greater price volatility, which requires a number of competition and regulatory safeguards to protect consumers that include a local and system-wide market power mitigation mechanism, transmission planning process that recognizes the competitiveness benefits of upgrades, dynamic pricing that protects consumers and retailers from imprudent exposure to short-term prices. Regulatory policies that encourage customer choice such as widespread deployment of interval meters, mechanisms for customers to share their data with third-party providers of energy services, and clearly defined default provider prices and obligations provide further protections for consumers while still providing the price signals necessary for consumers to adopt beneficial technologies and pricing structures that will facilitate the least cost transition to significantly more intermittent renewable generation capacity.

Figure 1. Two Part Tariff Pricing

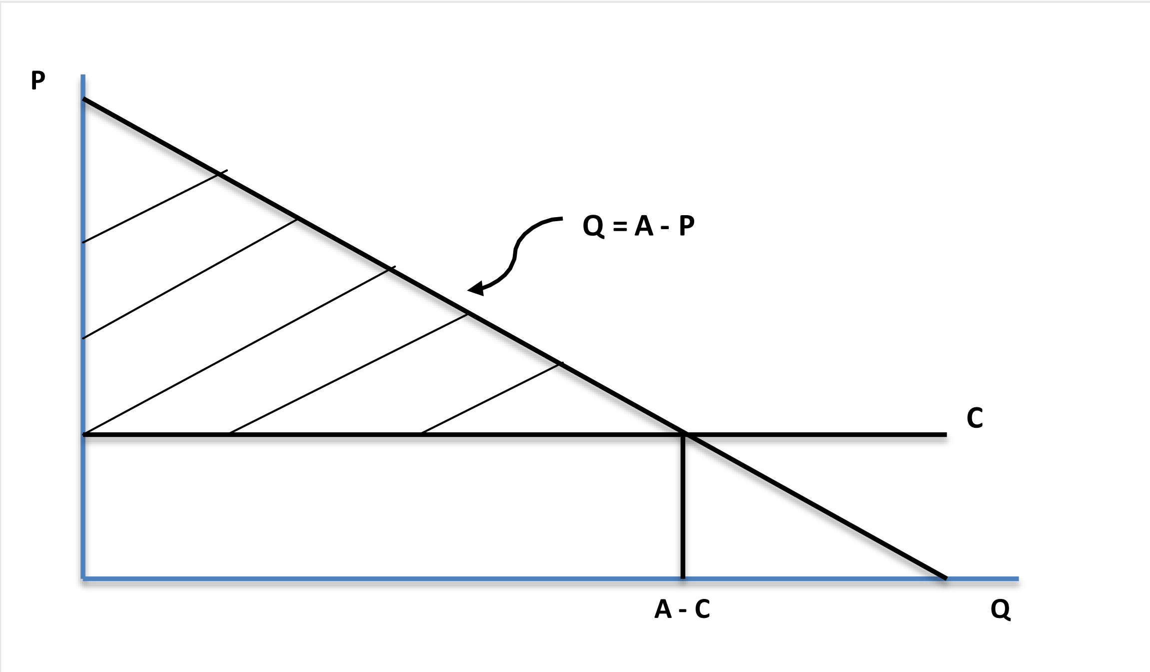


Figure 2. Worst-Case Fixed Fee Determination

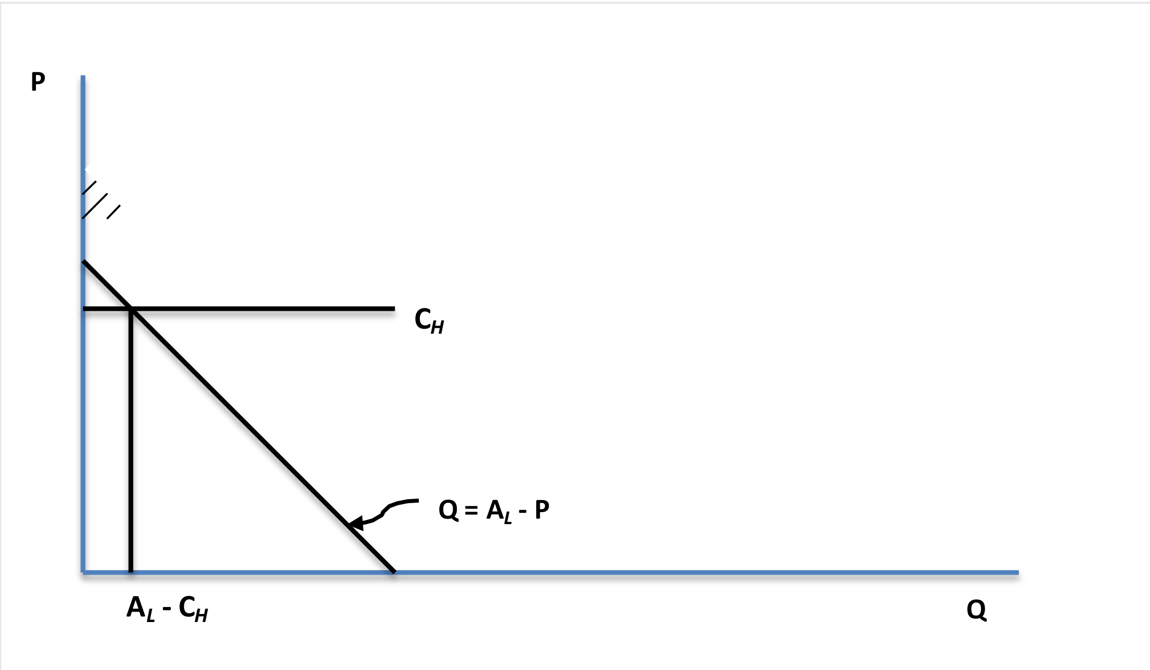
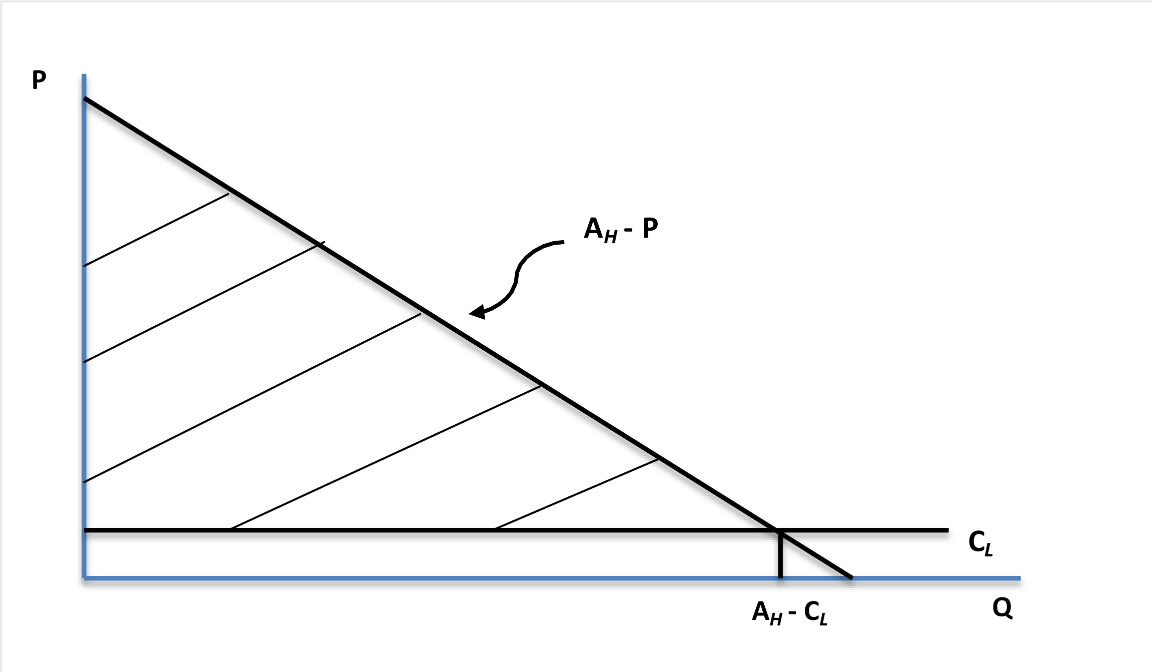


Figure 3. Best Case Fixed Fee Determination



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