2018-05-23

Implications of Implementing an Efficient Residential Transmission and Distribution Tariff and an Efficient Reimbursement Price for Excess Rooftop Solar Production in Alberta

Renborg, Lars Georg

UNIVERSITY OF CALGARY

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by

Lars Georg Renborg

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE

DEGREE OF MASTER OF ARTS

GRADUATE PROGRAM IN ECONOMICS

CALGARY, ALBERTA

MAY, 2018

Abstract

Rooftop solar is forecast to grow in Alberta to 5878 MW of installed capacity by 2030. The efficient level of rooftop solar installed by 2030 is 3634 MW. The additional 2244 MW of solar by 2030 is caused by incorrect residential transmission tariffs and incorrect reimbursement prices for excess solar production. The efficient level of rooftop solar (3634 MW by 2030) minimizes electricity costs for Albertans. The additional MW of solar will cost Albertans between 214 and 230 million dollars (2017 Canadian dollars) over the next thirteen years in additional electricity costs compared to if the same electricity had been produced from the grid. Updating the transmission tariff and the reimbursement price for excess solar production will save Albertans between 214 and 230 million dollars in electricity costs over the next thirteen years.

Acknowledgements

I would like to thank Dr. Church all of his comments and attention throughout the writing process. Also thank you to my parents and Azadeh for their support throughout the process. Thank you to Dr. Walls, Dr. Hollis and the neutral chair for agreeing to sit on my panel. Also thank you to Wesley Manfro from ENMAX Power Corporation for providing information on the consumption of residential customers. Thank you to Andrew Wilkins and David Bell from the MSA for their comments on my initial proposal.

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Chapter 1 Introduction

Alberta currently has a relatively small amount of rooftop solar compared to other jurisdictions in North America.[1] Rooftop solar refers to small solar systems (<15kW of capacity) that are installed on residential households.[2] There is potential for rooftop solar to grow significantly in Alberta due to the decreasing cost of solar panels and the increasing cost of using electricity from the grid.[3]

The potential for growth in rooftop solar in Alberta leads to the following research question: will the current transmission and distribution tariffs and electricity prices for residential customers incent an efficient level of rooftop solar adoption in Alberta and if not what would the efficient transmission and distribution tariffs and electricity prices look like? To answer this question the paper forecasts rooftop solar adoption for residential customers in Alberta, reviews the current

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[1] In 2016, California had a Photovoltaic (PV) distributed generation (DG) penetration of 4.3% and Hawaii had 7.8%. Photovoltaic distributed generation penetration is defined as the percentage of energy produced in a region that is sourced from commercial or residential solar systems. Anderson, C. (2016). "Solar Leaderboard." Retrieved March 30th, 2017, from http://www.solarleaderboard.com/2016-solar-penetration-state/.

In comparison, 0.01% of Alberta's generating capacity in 2017 was sourced from small scale solar. (16MW/16261MW=0.0010)

Small scale solar is defined as solar systems that are 5 MW or less. Alberta and Solar Leaderboard have different definitions of distributed generation. Despite these differences, the percentages provide an indication of where Alberta sits relative to other jurisdiction.

For Alberta's Microgen report see AESO (2017). "Micro-generation in Alberta." Retrieved March 30, 2017, from https://www.aeso.ca/market/market-and-system-reporting/micro-generation-reporting/.

For Alberta's total generating capacity in 2016 see Alberta Energy. "Electricity Statistics." Retrieved November 4th, 2016, from http://www.energy.alberta.ca/electricity/682.asp.

[2] See section 5.2.2 in Chapter 5 for discussion of size of solar panels. A 15 kW rooftop solar system can produce over 1600 kWh of electricity per month. The average rooftop solar system is between 4 and 6 kW.

[3] See Chapter 6

tariff structure and provides a recommendation for how it can be updated to incent an efficient level of rooftop solar in Alberta.

The efficient level of rooftop solar adoption is the level that minimizes electricity costs for Albertans. If rooftop solar is the lowest cost form of electricity production, then it is efficient to install a large amount of rooftop solar to supply Alberta's electricity. If rooftop solar is a high cost form of electricity production relative to other technologies, then the efficient outcome is to have a small amount of rooftop solar installed.

Alberta is expected to have between 2965 and 5878 MW of rooftop solar by 2030. The lower solar forecast is based on a 12.75% nominal residential discount rate and the higher solar forecast is based on an 8.75% assumed nominal residential discount. Both solar forecasts are based on the economic incentive to install solar as a method of saving on electricity costs. The forecast considers all costs associated with consuming electricity from the grid, and what costs can be reduced/eliminated if a residential customer installs rooftop solar on their house. If a customer can save money by installing a rooftop solar panel they will switch.[4]

5878 MW of rooftop solar will be 44 percent of Alberta's forecasted peak demand in 2030.[5] This is a large investment in a new technology. The size of the investment in rooftop solar means that it is important that the investment is an efficient outcome. An efficient outcome is one that

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[4] See Chapter 5 and 6 for economic drivers of rooftop solar adoption and the results of the forecast.
[5] 5878 MW / 13231 MW = 0.44. Alberta Electric System Operator (2017). "2017 Long Term Outlook Data File." Retrieved August 28th, 2017, from https://www.aeso.ca/download/listedfiles/2017-LTO-data-file.xlsx.

minimizes electricity costs for Alberta. The major implication of the uptake in rooftop solar in Alberta is that it is likely to increase the cost of electricity in the province. The current and expected future cost of transmission, distribution, grid electricity and rooftop solar support that rooftop solar is a higher cost form of electricity compared to electricity sourced from the grid. The investment in solar is inefficient because the investment money could have been allocated to a lower cost form of electricity production.

Rooftop solar is a higher cost form of electricity production compared to grid electricity because rooftop solar does not realize large enough savings in distribution and transmission costs. The advantage of distributed generation over electricity sourced from the grid is that it is located directly where electricity demand exists. The benefit should be that transportation costs (transmission and distribution) are significantly reduced as a result of rooftop solar being installed. Unfortunately, this is not the case and therefore rooftop solar is a higher cost from of electricity production compared to electricity sourced from the grid.

If you create prices for electricity production, distribution and transmission that reflect the incremental cost of producing those products, you will incent producers and consumers to choose production technologies that are the lowest cost and provide the most value to the economy. The problem currently is that the transmission tariff that is in place does not represent the incremental cost of using the transmission network. Also, the electricity price that residential customers receive for the excess electricity they produce from solar panels is also not set at the incremental cost of electricity generation. This creates an incorrect price signals for residential electricity customers.

When prices reflect the incremental cost of producing goods, the value to the economy as a whole is maximized. If prices reflect the incremental cost of consuming a good, then the purchase of a good covers the cost of producing it.[6] Also, if consumers have the ability to choose which goods they want to consume, then consumers will choose the goods with the lowest incremental cost. This process creates low cost products that consumers value.

This paper applies the concept of incremental cost pricing, or marginal cost pricing in economics, to the residential rooftop solar market. The paper recommends that residential transmission tariff is updated to better reflect the marginal cost of transmission. This would mean implementing a fixed charge for residential transmission services and decreasing the current variable charge. For distribution, the current tariff is already a fixed and variable charge and therefore it is closer to the incremental cost of producing electricity distribution.

The reason that a mixture of fixed and variable charges reflects the marginal cost of distribution and transmission is that the distribution and transmission industries are natural monopolies. A natural monopoly is an industry that has decreasing average costs.[7] The more that is produced the lower the average cost becomes. If the average costs are decreasing it also means that the marginal cost sits below the average cost. If the price sits at the marginal cost of production and

[6] The incremental (or marginal) cost of producing a good will cover the cost of producing the good provided that the marginal cost is at or above the average cost of production. If the marginal cost sits below the average cost of producing the good, then other price mechanisms need to be used to cover all costs. Transmission and distribution firms have marginal costs below the average cost of production and therefore they require an additional fixed charge to recover all of their costs.

[7] Decreasing average costs are a sufficient but not necessary condition for natural monopoly. Industries with increasing average costs can still be natural monopolies. See Section 12.4 for discussion of natural monopoly.

the marginal cost of production is below average cost, then the firm will not be able to recover all of its costs. The price needs to be at or above the average cost for the firm to recover all of its costs. A mixture of fixed and variable charges allows the utility to set a low unit price and recover remaining costs with a fixed charge.

One problem with using a fixed charge to recover costs is that consumers may not be willing to pay it. Residential electricity customers also have the option of bypassing the fixed charge by disconnecting from the grid entirely. This requires installing storage capacity as well as installing rooftop solar. Customers that install rooftop solar are still connected to the grid. Disconnecting from the grid required further investments in storage so that the consumer can consume electricity when the sun goes down.

This paper provides a tariff recommendation that would create an efficient outcome without disconnection from the grid. Given the size of storage required to disconnect from the grid, it is unlikely that consumers would find it economically advantageous to disconnect, even with high fixed charges to remain on the network. Without significant advancements in storage technology, disconnection is unlikely. For this reason, the tariff recommendation in this paper applies to customers that are unable to disconnect.[8]

The long-run marginal cost of transmission is the incremental cost of all costs associated with transmission. This includes but is not limited to the capital invested to transport the electricity

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[8] See Chapter 8 for analysis of the ability to disconnect.

and labour required to operate the capital. Each additional kilowatt (kW) or kilowatt hour (kWh) of electricity transported on the transmission network requires an incremental amount of capital and labour. The long-run marginal cost of transmission is that incremental cost.

The long-run marginal cost of transmission and distribution changes depending on when the electricity is consumed and at what rate the electricity is consumed at. A fixed and variable tariff communicates to customers that transmission and distribution have decreasing average costs and the marginal cost of production is low. The tariff also needs to communicate to customers that the long-run marginal cost of transmission and distribution increases when customers consume electricity at peak times.

KW and kWh refer to methods of measuring electricity consumption. KWh is the volume of electricity consumed while kW is the rate in which electricity is consumed. In terms of distance and speed, kW is the equivalent of kilometer per hour (km/h) and kWh is the equivalent of kilometers (km). A car that consistently drives at a high speed (km/h) will also travel a large distance (km). Similarly, those who consistently consume electricity at a high rate (kW) will also consume a large volume of electricity (kWh).

The rate that a customer consumes electricity at peak times (kW) has a big impact on the long-run marginal cost of transmission and distribution. Capital costs that are incurred from customers consuming a good at peak usage times are called capacity costs. Peak usage times means periods of time where many customers are using the service.

Those who consume electricity at a high rate during times of peak electricity use have a high capacity cost. Capacity cost is an important cost that is included in the long-run marginal cost of production. Those who consume electricity at a high rate during peak times have a higher capacity cost and long-run marginal cost of transmission and distribution than those that consume electricity at a low rate during peak times. The equivalence on a road network would be the cost of travelling quickly during rush hour is much higher than the cost of travelling slowly or completely avoiding the road network during peak times. This is because there are capacity costs associated with creating roads that can accommodate high speed traffic during rush hour. In electricity there is a high cost associated with transporting electricity on distribution or transmission lines at a high rate during times of peak electricity use.

Alberta's residential meters are not able to measure the rate that customers consume electricity at peak times. The current meters only measure the volume of electricity consumed over the period of a month (kWh). The recommended tariff charges based on kWh with the assumption that those who consume a large volume of electricity will also consume electricity at a high rate during peak times. There is evidence to suggest that residential customers that consume a large volume of electricity monthly (kWh) also consume electricity at a high rate during peak hours (kW).[9]

Changing the transmission tariff to the marginal cost of transmission (charged based on kWh) will incent an efficient level of rooftop solar in Alberta by communicating the incremental cost

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[9] See Section 11.1 for discussion on the relationship between volume of electricity consumed and rate that electricity is consumed at peak times.

of transmission to rooftop solar customers. Residential customers will choose between rooftop solar and grid electricity using transmission prices that reflect the incremental cost of production. The technology with the lower cost will serve residential customers.

There are two studies from Colorado and California that show that the incremental cost of distribution and transmission are very low.[10] If Alberta's incremental cost of transmission and Alberta's incremental cost of distribution are the same as the incremental costs in Colorado and California, then rooftop solar will be pushed out by three to eight years, depending on the area of the province. Updating the transmission and distribution tariffs to sit at the long-run marginal cost of transmission and distribution reduces the incentive to install rooftop solar. Forecasts of transmission and distribution prices, electricity prices and solar costs support that rooftop solar adoptions will be delayed if transmission and distribution tariffs are updated.[11]

Transmission tariffs in Alberta are not set at the incremental cost of transmission and this leads to the incorrect price signal that rooftop solar is a lower cost form of electricity production compared to grid electricity. Consumers are incented to install 5878 MW of rooftop solar by 2030. If prices were set at the incremental cost transmission and distribution, taken from the cost studies from Colorado and California, the level of rooftop solar installed would be 3634 MW by

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[10]See Chapter 14 and 15 for overview of the studies from Colorado and California.

Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

Cohen, M. A., et al. "Effects of distributed PV generation on California's distribution system, part 2: Economic analysis."

[11] See Section 15.2 for analysis of the impact of updating transmission and distribution tariffs on rooftop solar adoption.

2030. The alternative solar forecast (using a 12.75% nominal discount rate) of 2965 MW by 2030 will decrease to 0 MW by 2030 if the same incremental cost of transmission and distribution are used to set tariffs. Rooftop solar adoptions are pushed out to later years when the prices for transmission and distribution are set at the incremental cost of production.[12]

The installation of rooftop solar creates an inefficiency in Alberta's electricity market. Customers that could be consuming electricity from the grid are using a higher cost alternative (rooftop solar). The installation of rooftop solar increases Alberta's electricity costs above what they need to be.

The additional electricity costs incurred by Alberta's residential customers from the installation of rooftop solar can be calculated. The forecast of solar adoptions uses the present value all electricity costs associated with consuming electricity with rooftop solar installed and compares it to the present value of all electricity costs associated with consuming electricity exclusively from the grid. The current transmission and distribution tariff structure incents residential customers to install solar because the present value of the cost of consuming electricity with solar panels is less than the present value of the cost of consuming electricity from the grid. By updating the tariffs the model recalculates the present value of cost associated with consuming electricity with solar compared to the present value of cost of consuming electricity exclusively from the grid. The result is that when tariffs are set at the long-run marginal cost of transmission and distribution, rooftop solar power becomes a high cost form of electricity compared to

[12] See Section 15.2 for the calculation of the level of solar installation when transmission and distribution are set at the long-run marginal cost of transmission and distribution.

consuming electricity from the grid. The reduced savings from installing rooftop solar pushes out the solar adoptions to a later date.

The difference between the present value of the costs associated with using solar and the present value of the costs associated with consuming electricity exclusively from the grid is the inefficiency of solar. It is the additional energy, transmission and distribution costs incurred as a result of installing solar instead of consuming electricity from the grid.

The present value of the difference between electricity costs from using solar compared to electricity costs from using the grid from 2017 to 2030 ranges from 214 to 230 million dollars (2017 Canadian dollars). The 230 million dollar calculation uses an 8.75 % nominal discount rate or the equivalent 6.6% real discount rate to discount future additional electricity costs resulting from installing rooftop solar panels. The 214 million dollar calculation uses a 12.75% nominal discount rate, of the equivalent 10.5% real discount rate to discount future additional electricity costs resulting from installing rooftop solar panels [13]

The paper recommends that the transmission tariff be updated to avoid spending an additional 214 to 230 million dollars on electricity costs in Alberta over the next thirteen years (2017-2030). If transmission tariffs are not updated, customers will be incented to invest in a higher cost form of electricity than is necessary.

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[13] The present value calculation discounts electricity costs by a 6.6 % real discount rate. 6.6 % is 8.75 % deflated by a 2 % inflation rate. 1.0875 / 1.02 = 1.066. Also, the 12.75% nominal discount rate is deflated using a 2% inflation rate. 1.1275/1.02=1.105. See Chapter 15 for full calculation.

Another consequence of high rooftop solar penetration is that transmission and distribution tariffs will need to be increased to make up for lost revenue. When a customer installs rooftop solar the amount of electricity that they consume off the grid decreases. Since residential distribution and transmission tariffs are charged based on the kWh's that customers consume from the grid, the transmission and distribution revenues that those companies receive will decrease. In order to maintain the same level of revenue, the transmission and distribution companies will need to increase tariffs as a result of more rooftop solar installations.[14]

The increase in tariffs would accelerate the pace of rooftop solar adoption. Early rooftop solar adopters will decrease revenue for transmission and distribution and this will lead to higher transmission and distribution tariffs which will incent more rapid solar adoption for the remaining customers on the network.

The increased pace of rooftop solar adoption from early adopters increasing tariffs is sometimes referred to as a death spiral. The impact of rooftop solar adoption on tariffs compounds onto itself because the more customers substitute the greater the incentive to substitute becomes. The impact of the death spiral is that it will accelerate the solar adoption within each of the four service areas in the province. Alberta is separated by four major distribution facility owners: Enmax Power Corp., EPCOR, Fortis Alberta, and ATCO Electric.

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[14] See Section 7.1 for explanation of how transmission and distribution costs would increase as a result of increased rooftop solar adoption.

The four distinct service areas mitigates the impact of the death spiral to each of the four service areas. ATCO Electric, Fortis, Enmax and Epcor all have their own transmission and distribution tariffs in the province. This means that the impact of solar adoptions in one service area does not impact the other three service areas. The four companies have their own revenue requirements and therefore solar adoptions in one service area do not impact solar adoption in the others.

The distinct service areas limit the effects of the death spiral to each DFO's service area. Early adopters in ATCO's service area would will accelerate adoption within ATCO's service area. Accelerated adoption in ATCO's service area does not increase the pace of solar adoption in Fortis, Enmax or Epcor's service areas.

Chapter 7 calculates the impact of solar adoptions on transmission and distribution tariffs and shows that death spirals will occur in each service area. Tariffs increases will accelerate solar adoption within each service area, but the impact will not spill over to other service areas.

The price that rooftop solar customers receive for the electricity they put back on the grid also need to be updated to better reflect the long-run marginal cost of generating electricity on the grid. The current system uses the retail rate of electricity to reimburse rooftop solar customers for excess electricity produced by solar panels. The retail rate of electricity is the wholesale price of electricity plus a rate of return earned by electricity retailers.[15] The wholesale price of electricity

[15] The retail rate is the result of electricity retailers purchasing electricity from the wholesale electricity market and selling it to residential customers. On average, the electricity retailer needs to earn a rate of return to cover the opportunity cost of participating in the market. This is why the wholesale price of electricity is different from the

is a better indicator of the long-run marginal cost of electricity because it is the price that generators receive for producing electricity in Alberta. Rooftop solar customers become generators in Alberta when they produce more electricity than they consume. For this reason, rooftop solar customers should be reimbursed for excess solar production at the same rate as other generators in the province. Rooftop solar customers should be reimbursed for excess electricity produced by solar panels using the wholesale price of electricity rather than the retail rate.[16]

There are many examples of regulatory bodies in the United States changing transmission and distribution tariffs as well as the reimbursement price for excess solar production in response to increased rooftop solar penetration. Arizona changed their transmission and distribution tariffs to include a larger fixed charge and Hawaii decreased the reimbursement price for excess solar production in response to more rooftop solar adoption in those states. These outcomes in other jurisdictions support the recommendations made in this paper.

The Alberta Utilities Commission (AUC) also finished a review of the enablers and barriers to distributed generation. The study conducted by the AUC demonstrates that this topic is important to Alberta's current policy makers.[17]

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retail rate. See Chapter 13 for discussion of the efficient electricity price to reimburse solar customers for excess solar production.

[16] Excess electricity produced by solar panels refers to electricity that is produced by a residential customer's solar panels but is not consumed on-site.

[17] See Chapter 16 for review of Arizona, Hawaii and Alberta's tariff hearings.

1.1 Overview of the Paper

Chapter 2 covers the electricity markets that impact a residential customer's decision on whether to install rooftop solar. The transmission and distribution markets are covered in larger detail in Chapters 9, 10 and 11 due to their complexity and the large impact they have on the rooftop solar market.

Chapter 3 explains efficiency and how it relates to natural monopolies and tariff design. Efficiency is the theory supporting marginal cost pricing. Marginal cost pricing creates an outcome that minimizes cost and maximizes value in an economy. Marginal cost pricing in the transmission, distribution and electricity generation markets leads to an efficient level of rooftop solar installations. Without marginal cost pricing, consumers will choose technologies that are not the lowest cost alternative. Rooftop solar will grow to 5878 MW by 2030 if transmission tariffs for residential customers are not updated. Updated tariffs set at the long-run marginal cost are necessary to communicate the high cost of installing rooftop solar.

Chapter 4 then follows with a review of the microgeneration legislation currently in place in Alberta, along with the current solar subsidies implemented by the Alberta government.

Chapter 5 then covers what drives rooftop solar adoptions. The economic drivers of rooftop solar adoption include solar costs, transmission and distribution rates, and the residential customer's discount factor. Chapter 6 follows with how quickly residential customers are likely to adopt solar with the current transmission and distribution tariffs in place. This is important because it shows what level of rooftop solar Alberta can expect if the current transmission and distribution tariffs are not updated. The paper uses forecasts of solar costs along with forecasts of transmission and distribution tariffs and electricity prices to create a prediction of how many MW of rooftop solar will be installed over the next thirteen years.

A second rooftop solar forecast is included that considers the impact of rooftop solar on transmission and distribution tariffs (Chapter 7). Rooftop solar decreases the amount of electricity that gets consumed off the network because the solar panels offset the consumption of households. The decrease in electricity consumed means that the revenue collected by distribution companies decreases. The decrease in revenue requires the distribution companies to increase tariffs. The increase in tariffs is necessary because without it the distribution companies cannot recover their costs (this is assuming that the distribution company's costs do not change as a result of rooftop solar adoption).[18] The increase in tariffs impacts the incentive of other residential customers to adopt.

Chapter 7 calculates the impact of tariff increases on solar adoption in Alberta. The tariffs increases would accelerate solar adoption in each service area but it does not change the MW of solar installed by 2030. Without any tariff increases resulting from rooftop solar adoption, Alberta's residential customers will install 5878 MW by 2030. With the impact of tariff increases residential customers will still install 5878 MW by 2030. The impact of the tariff increases is that

[18] Chapter 14 shows that the distribution and transmission savings created from the installation of rooftop solar are small. The savings associated with solar are small because solar has a limited ability to reduce peak electricity demand for residential customers. Most transmission and distribution savings come from reducing peak demand on the network. If the customer fully disconnected from the grid, then the reduction in peak electricity demand would be significant. Without full disconnection, the impact on peak electricity demand is small.

the rate of adoption in ATCO and Fortis' service areas increases. The tariff increases accelerate solar adoption for the province and this creates a larger inefficiency in Alberta's electricity market.

Chapter 8 discusses the issue of disconnection. Solar customers are unlikely to fully disconnect from the grid because this requires a significant amount of storage capacity as well as large rooftop solar systems. Storage is necessary because residential customers still consume electricity when the sun sets. Solar energy from the day needs to be stored so it can be consumed in the evening. Disconnection is unlikely because the level of storage required in Alberta is prohibitively high.

The paper follows with how the current residential transmission and distribution tariffs are set and how they could be updated to incent an efficient level of rooftop solar. The process used to determine the current distribution and transmission tariffs is covered (Chapter 9 and 10) as well as the justification for the current distribution and transmission tariffs (Chapter 11). The current tariffs are set using the fully distributed cost method. The paper introduces marginal cost pricing and explains how this would be implemented in Alberta. Marginal cost pricing recommends that transmission and distribution charges should be set at the long-run marginal cost of transmission and distribution (Chapter 12).

Chapter 13 covers the reimbursement price that rooftop solar customers receive for electricity. The current systems provides a reimbursement price that is inefficient. The paper recommends a lower reimbursement price set at the wholesale price of electricity.

Studies on the rooftop solar's impact on the transmission and distribution industries provide estimates of the long-run marginal cost of transmission and distribution (Chapter 14). The estimates are compared to the current transmission and distribution tariffs in Alberta (Chapter 15). There are some distribution tariffs in Alberta that sit very close to the long-run marginal cost of distribution (Enmax and Epcor). For the most part, transmission and distribution tariffs are higher than the long-run marginal cost of transmission and distribution. If the transmission and distribution tariffs in Alberta were set at the long-run marginal cost estimates provided in Chapter 14, the incentive to install rooftop solar would be reduced. The long-run marginal cost of transmission and distribution are low enough in those studies that the incentive to install solar is reduced. This is because the current transmission and distribution tariffs create large cost savings for residential customers that install solar. If the transmission and distribution tariffs decrease, the savings from installing solar also decrease and the incentive to install solar goes down.

The net cost of installing 5878 MW of solar by 2030 is 230 million dollars (2017 Canadian dollars). The net cost of installing the lower solar forecast (2965 MW by 2030) is 214 million dollars (2017 Canadian dollars). The 214 and 230 million dollar calculations are the present value of additional electricity costs associated with installing rooftop solar compared to electricity from the grid. The calculations subtract the cost of consuming electricity using electricity from the grid from the cost of consuming electricity with solar panels. The additional cost associated with rooftop solar panels is between 214 and 230 million dollars over 13 years.

The inefficiency calculations include the social cost of carbon abatement because Alberta has implemented a carbon tax that is reflected in the price of electricity in Alberta.[19]

Chapter 16 covers a regulatory proceeding held in Arizona on residential tariff design as it relates to rooftop solar adoption. Arizona's experience is used to inform the best route for Alberta. A hearing in Hawaii is also covered as it relates to the reimbursement price that solar customers receive for excess solar generation. The hearing that was undertaken in Alberta in 2017 on distributed generation is also briefly discussed.

The paper concludes with a recommended transmission and distribution tariff structure and an estimation of the inefficiency of installing rooftop solar. The recommended tariff structure can be applied in upcoming tariff hearings in Alberta.

[19] See section 15.2 and 15.3 for details of calculation. The current carbon abatement cost in Alberta is set at $30/tonne of carbon emitted.

Chapter 2 Introduction to Alberta's Electricity Industry

There are four major sectors in Alberta's electricity industry: power generation, power transmission, power distribution and retail power. All four of these sectors influence the efficiency of rooftop solar.

Distribution and transmission are the major focus of this paper because of the impact they have on the efficiency of rooftop solar. The retail and power generation markets are also covered to support the recommendation on the reimbursement price for electricity sold back onto the grid.

Power generation in Alberta is allocated through a market. This means that the price of electricity is determined by electricity participants bidding to supply electricity to the grid (the wholesale electricity market). In Alberta, the wholesale electricity market is called the Power Pool. [20]

The Alberta Electric System Operator (AESO) is a non-for-profit corporate entity that operates the Power Pool. Suppliers of electricity submit offers to the AESO for the quantity and price of electricity they can supply the market. The AESO sorts the offers from lowest to highest to create the merit order. The lowest priced offer is dispatched first, and the AESO dispatches the offers on the merit order until the demand for electricity is met.[21]

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[20] Alberta Utilities Commission. "Alberta's energy market." Retrieved September 28, 2016, from http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx.

[21] Alberta Electric System Operator. "Guide to Understanding Alberta's Electricity Market." Retrieved September 28th, 2016, from http://www.aeso.ca/29864.html.

Alongside the Power Pool there is a forward market. The forward market allows participants to buy and sell electricity before the production and consumption occurs.[22] The regulated rate option, which is one of the electricity prices that residential customers can choose from, purchases electricity from the forward market.[23]

Deregulation in Alberta occurred between 1996 and 2002. Before deregulation in Alberta, the power generation market was regulated using a cost of service regulatory model.[24] Cost of service means that generation companies would submit the costs incurred from building and operating generation and the Alberta Utilities Commission (AUC) would reimburse the companies through rates charged to consumers.[25]

As a result of deregulation, the AUC is not responsible for reimbursing generation companies for costs. Under the current system, generation companies must recover all their costs from the prices received in the Power Pool. Over the next five years, the AESO is introducing a capacity

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[22] Market Surveillance Administrator (2010). "Alberta Wholesale Electricity Market." Retrieved September, 2016, from http://albertamsa.ca/uploads/pdf/Reports/Reports/Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf.

[23] Government of Alberta. "ELECTRIC UTILITIES ACT REGULATED RATE OPTION REGULATION." Retrieved September 28th, 2016, from http://www.qp.alberta.ca/documents/Regs/2005_262.pdf.

[24] Alberta Utilities Commission. "Alberta’s energy market." Retrieved September 28, 2016, from http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx.

[25] Regulation Body of Knowledge 6. "Cost of Service Regulation." Retrieved September 28th, 2016, from http://regulationbodyofknowledge.org/glossary/c/cost-of-service-regulation/.

market. Under the new system generators will recover their costs from the capacity market and a modified power pool (energy market).[26] The paper considers the impact of the capacity market by using the average energy cost as the electricity price forecast as an input for the rooftop solar forecast in Chapter 6 (see Figure 2). The average energy cost is the electricity price in the power pool for years prior to the implementation of the capacity market and the pool price plus the capacity price in years after the capacity market is implemented. This ensures that the impact of the capacity market is included in the rooftop solar forecast.

Transmission moves electricity from electricity suppliers to distribution networks. Distribution receives electricity from the transmission network and serves individual customers. Transmission is regulated in Alberta using a cost of service regulatory model. Distribution is regulated using performance based regulation. The residential tariffs for distribution and transmission have a big impact on the economic incentive to install rooftop solar. Efficient pricing in these industries is essential to incent an efficient level of rooftop solar in Alberta.

The retail power market is the power market for residential customers. Retailers provide electricity to residential consumers by purchasing blocks of energy from the power pool and selling to residential customers. The retail power market, alongside the power pool, determines the retail rate of electricity (price of electricity for residential customers).[27] Rooftop solar

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[26] AESO (2016). "Capacity Market Transition." Retrieved March 3rd, 2017, from https://www.aeso.ca/market/capacity-market-transition/.

[27] Alberta Energy. "About Electricity Prices." Retrieved July 25th, 2017, from http://www.energy.alberta.ca/Electricity/679.asp.

customers get reimbursed using the retail rate of electricity. This means that if a residential customer produces more electricity than they consume, over the course of a month, the excess electricity is reimbursed to them at the retail rate of electricity.[28]

The power, distribution and transmission and retail markets all contribute to creating prices for residential electricity customers. Efficient prices in all four of these markets creates an efficient outcome in the residential solar market. Efficient prices are prices that reflect the marginal cost of producing a service. The concept of efficiency and how it relates to marginal cost pricing is covered in the next chapter.

[28] See Chapter 4 for a more detailed explanation.

Chapter 3 Economic Efficiency

Economic efficiency refers to an outcome that maximizes total surplus. Total surplus refers to the value that producers and consumers get from participating in the economy. Total surplus can be separated into producer and consumer surplus.

Consumer surplus is the amount a consumer would have to be paid to forgo the opportunity to purchase as much as she wants of the good at the given price. It is the value that a consumer gets from consuming a good. Consumer surplus for a market is the aggregate of all consumers in a market.[29] Consumer surplus in the residential electricity market is the value that residential customers get from consuming electricity.

Producer surplus for an individual firm is the amount the firm would have to be compensated to forgo the opportunity to sell as much as they would like at a given price. Producer surplus can be defined in the short run and the long run. Both long-run and short-run producer surplus is the difference between the revenues and the avoidable costs of the firm.[30] Avoidable costs refer to costs that a firm can avoid if they do not produce. In the case of transmission and distribution, line losses are an example of an avoidable cost. Line losses are electricity lost due to heat and other factors. If a transmission company does not transport electricity, they do not incur any line losses.

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[29] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

[30] Ibid.

Short-run avoidable costs are different than long-run avoidable costs. Only some of a firm's costs are avoidable in the short run. Costs that are not avoidable in the short-run are called 'sunk'. In the long-run, all costs are avoidable. An example of a long-run perspective is that the firm is considering entering a market, and they can avoid all costs by choosing not to enter. In the long-run, all costs are included in the calculation of producer surplus.

The paper takes the long-run perspective when making efficiency arguments for the adoption of solar. The paper compares all costs associated with rooftop solar to all costs associated with grid electricity. The technology with the lower costs will maximize total surplus, in the long-run. In plain English, the technology with the lowest cost will create the most value to society.

Setting prices at marginal cost maximizes total surplus by ensuring that the lowest cost producer is given the first opportunity to produce in the market. The lower the cost of production is, the more producer and consumer surplus is created. Low costs create larger profits for producers and more value for consumers.

If prices do not reflect the marginal cost of production then the total surplus created in the economy decreases. Prices set at the marginal cost of production communicate the incremental cost of that good. If that price is misstated, a customer will misinterpret the cost of consuming a good. This can lead them to switch to a different technology before the total cost of one technology falls below the alternative.

Prices set at the incremental cost of production communicate to the cost of consuming an additional unit of that good. If those prices are set correctly the consumer will be able to choose the lower cost alternative. If the price is set higher or lower than marginal cost, then consumers are likely to choose a producer that is not the lowest cost. If a high cost producer uses a low price, then consumers will choose that producer despite it not being the lowest cost option.

If consumers choose production technologies that are in reality high cost, it unnecessarily increases the cost of producing that good. The low cost alternative is displaced by the high cost alternative. While both the high and low cost option can participate in the market, it would be more efficient if only the low cost option supplied customers. Provided that the low cost option is capable of serving all customers, it is the cheapest and most efficient method of producing the good.

In electricity the high and low cost options are rooftop solar and electricity sourced from the grid. Electricity sourced from the grid is displaced by electricity produced by rooftop solar. This happens because the price for transmission is set above the long-run marginal cost of transmission. Consumers respond to this by looking for a lower cost alternative. The perceived lower cost alternative is rooftop solar. Consumers substitute to rooftop solar when grid electricity using the transmission network is still the lowest cost form of production.[31]

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[31] Rooftop solar is a high cost form of electricity production because it does not realize significant savings in transmission and distribution costs. The current transmission tariff overstates the transmission savings associated with rooftop solar. This leads to transmission companies subsidizing solar through the incorrect transmission tariff. The subsidy eventually needs to be recovered from transmission customers and this leads to increasing transmission rates. The impact of increasing transmission rates as a result of rooftop solar adoption is covered in Chapter 7.

The efficiency calculations done in this paper only considers the productive inefficiency associated with rooftop solar. They do not consider the allocative inefficiency associated with solar. Allocative inefficiency considers both consumer and producer surplus whereas productive inefficiency only considers producer surplus. Consumer surplus is not considered because electricity customers are highly inelastic. The quantity of electricity consumed by residential customers is not impacted by the price. Without a change in quantity consumed, consumer surplus remains the same.

If the prices of electricity, transmission, distribution and solar panels represent the marginal/opportunity cost of using those services or products, then residential customers will adopt rooftop solar when it is the lowest cost form of electricity available.

If the price of electricity, transmission, distribution or solar panels do not represent the marginal/opportunity cost of using those services or products, then it can lead to residential customers adopting solar before or after it is the lowest cost form of electricity. In the case of rooftop solar, consumers substitute to rooftop before it is the lowest cost from of electricity. The high transmission price creates this undesired early adoption.

Chapter 12 covers how to find the long-run marginal cost of transmission and distribution in more detail. This includes how to deal with capacity costs (a type of cost that forms a large part of transmission and distribution costs). The next chapter maps out the rooftop solar adoption process, starting with the current regulation for solar adoptions in Alberta.

Chapter 4 Microgeneration Regulation

In 2008 the Alberta government issued a Micro-generation regulation that allowed Alberta businesses and households to install renewable or alternative energy sources with a capacity less that 1 MW.[32] The regulation allowed residential customers to install solar on their homes and outlines the process of reimbursing residential customers for the electricity that they produce.

In 2016 the regulation was amended to create more flexibility for distributed generation customers. It increased the limit on capacity for microgeneration to 5 MW and allows micro generators to serve adjacent sites.[33]

As of January 2017, Alberta had 17.2 MW of generation capacity installed under the microgeneration regulation.[34] This is 0.1 percent of Alberta's total generating capacity.[35] A large increase in the capacity installed under the microgeneration regulation would have an impact on the efficiency of Alberta's electricity market.

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[32] Government of Alberta (2008). "MICRO-GENERATION REGULATION." Retrieved July 27th, 2016, from http://www.qp.alberta.ca/documents/Regs/2008_027.pdf.
, ibid.

[33] Alberta Energy (2017). "What is Micro-generation?". Retrieved August 7th, 2017, from http://www.energy.alberta.ca/Electricity/microgen.asp.

[34] Ibid.

[35] 17.2MW/16261MW = 0.1% Alberta Energy. "Electricity Statistics." Retrieved November 4th, 2016, from http://www.energy.alberta.ca/electricity/682.asp.

The micro-generation legislation in Alberta only allows consumers to install rooftop solar panels that produce zero net electricity over the course of a year. Systems larger than this are not approved. [36] Zero net annual production results in positive net solar production in the summer months and negative net production in the winter months. The restriction limits the size of solar systems for residential customers.

The amendment's increase from 1 MW to 5 MW does not impact the residential sector because residential solar installations do not reach this size. The ability to serve adjacent sites would apply to some residential customers. The regulation states that if adjacent sites are owned or leased by the same customer, are fed by the same distribution feeder, and are charged the same rate for electricity, they can be included with the electricity served by the distributed generation.[37]

The amendments to the legislation has the biggest impact on commercial customers. Single family housing in Calgary or Edmonton would typically only have a single building and would not be impacted by the amendments. Single family housing in rural areas might have multiple buildings. Farmers and university campuses were listed as parties that would benefit the most from the amendments.[38] Farmers and universities are not included in the residential rate class.

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[36] Solar Energy Society of Alberta (2015). "FAQs." Retrieved November 14, 2016, from https://solaralberta.ca/content/faqs.

[37] Government of Alberta (2017). "THE ALBERTA GAZETTE, PART II, JANUARY 14, 2017 ". Retrieved August 7th 2017, from http://www.qp.alberta.ca/documents/gazette/2017/pdf/01_Jan14_Part2.pdf.

[38] Government of Alberta (2016). "Albertans now allowed to generate more green electricity." Retrieved August 7th, 2017, from https://www.alberta.ca/release.cfm?xID=450415A625D10-069C-4633-02E78D217D3C1929.

Note that the restrictions on distribution sites means installations on attached housing (apartment buildings, condos and duplexes) need to be done by the building owner.[39] Since it is less likely that building owners would install solar on behalf of their tenants, the forecast in Chapter 6 assumes that apartment buildings, condos, and duplexes would not be able to substitute to solar. This is done by excluding the quintiles that include residents living in attached housing.

Under the microgeneration regulation, residential customers pay for electricity based on the net electricity that they consume. Net electricity consumed is the difference between the electricity consumed by the customer and the electricity produced by the customer, over the course of one month. A residential microgeneration customer is charged the retail rate of electricity multiplied by their net electricity consumed.[40] The retail rate of electricity can either be the regulated rate option (RRO) or a competitive contract rate. This means that if a customer installs enough capacity to offset their electricity use over one year and the price of electricity stays relatively constant over the course of a year, they do not pay for electricity. Price changes on a month to month basis would impact the ability of a customer to avoid all electricity charges over a period of a year.

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[39] Energy Efficiency Alberta (2017). "FAQs." Retrieved August 9th 2017, from https://solar.efficiencyalberta.ca/faqs/.

[40] Government of Alberta (2008). "MICRO-GENERATION REGULATION." Retrieved July 27th, 2016, from http://www.qp.alberta.ca/documents/Regs/2008_027.pdf.

If the customer produces more electricity than they consumed in a month, the excess electricity is credited in the following month. This can be continued up until twelve months have passed. After 12 months, the retailer must pay any outstanding credit to the customer.[41]

The solar forecast in Chapter 6 calculates electricity costs on an annual basis. This means that monthly differences between electricity produced and electricity consumed are not considered. Only annual differences between consumption and production are modelled in the forecast.

The variable portion of the distribution tariff and the transmission tariff are also charged based on net electricity consumed. [42] If the customer produces more electricity than they consumed in a given month, the variable portion of the distribution tariff and the transmission tariff are zero. The excess electricity is applied to the net electricity consumed in the following month, which leads to further savings in transmission and distribution charges.

The transmission charge for residential customers is solely based on the net electricity consumed by the customer. This means that if a residential customer produces enough solar electricity to offset all of their electricity use over the course of one year, they do not pay for transmission. Residential distribution tariffs are charged based on a fixed rate and the net electricity consumed. Residential microgeneration customers cannot avoid the fixed portion of the residential distribution tariff.

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[41] Ibid.

[42] Alberta Energy (2016). "What is Micro-generation?". Retrieved July 27th, 2016, from http://www.energy.alberta.ca/electricity/microgen.asp.

The next chapter assesses the potential growth of rooftop solar in Alberta and the different factors that impact solar adoption rates. The drivers of rooftop solar and the forecasted level of solar in Alberta is the first step in determining if Alberta will have an efficient level of solar and if the current transmission and distribution tariffs are not updated. The end goal of the paper is to calculate the inefficiency associated with rooftop solar. The solar forecast is the first step to achieve this goal.

Chapter 5 Economic Drivers of Rooftop Solar Adoption

Rooftop solar adoptions will grow in Alberta over the next thirteen years. The increase in rooftop solar will be driven by decreasing solar costs and increasing transmission and distribution tariffs.

The paper assumes that consumers will respond to the economic incentives of installing rooftop solar panels. If a consumer can save money on the cost of electricity by installing a rooftop solar panel, they will make the investment. The paper also includes the incentive for a residential customer to wait if the benefit of installing solar in the future is large enough. This is covered in section 5.2.10.

The economics of rooftop solar is evaluated using data available on the costs of small-scale solar panels, and the current and forecasted transmission and distribution tariffs for residential customers.

It should be noted that consumer may have other reasons for installing rooftop solar panels. Some may have a ‘green’ preference and will choose to install solar panels without it being an economically attractive investment.

The Transmission Rate Impact Projection (TRIP) workbook is a document published by the AESO in 2014. The purpose of the document was to give market participants, including residential customers, a forecast of all costs associated with consuming electricity in Alberta. The workbook forecasts electricity costs for residential and industrial customers.[43]

In 2017, the AESO updated the transmission and energy forecasts made in the TRIP workbook. The update is called the Transmission Rate Projection (TRP).[44]

This paper uses the TRIP workbook and the TRP to compare the cost of using electricity from the grid to the cost of using electricity from a rooftop solar panel. If consumers find it cheaper to install and use rooftop solar energy as compared to using electricity from the grid, they will have an incentive to install solar.

An economic factor that has a big impact on solar installations is the distribution company serving the customer. Distribution and transmission tariffs form a large portion of electricity charges in Alberta, and they have a big impact on the economic viability of rooftop solar.

5.1 Cost of Grid Electricity Compared to Cost of Solar Electricity

The lifespan of a typical rooftop solar panel is twenty-five years.[45] This is the investment period used to compare the cost of grid electricity to the cost of solar electricity.

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[43] Alberta Electric System Operator (2014). "AESO Transmission Rate Impact Projection (TRIP) Workbook - June 2014.". Retrieved July 24th, 2015, from http://www.aeso.ca/downloads/AESO_2014_Transmission_Rate_Impact_Projection_Workbook_-_Jun_2014.xlsx.

[44] AESO (2017). "Transmission Rate Projection." Retrieved February 13th, 2017, from https://www.aeso.ca/assets/Uploads/TRP-Factsheet-WEB.PDF.

Residential customers that install enough solar capacity to offset all of their electricity consumption over the course of one year, do not pay for electricity from the grid. Transmission fees are also zero. The customer is charged the fixed portion of the distribution tariff, a fixed charge from the electricity retailer for administration costs, and the cost of purchasing and installing rooftop solar panels.

The TRIP workbook lists the residential distribution and transmission tariffs faced by customers of the four distribution companies in Alberta. It forecasts the distribution tariffs based on the average performance based regulation (PBR) growth and inflation indexes.[46] It forecasts the transmission tariffs based on future transmission projects and their revenue requirements. The TRIP workbook also forecasts other charges like administration costs and the TRP forecasts electricity prices. These are summed to create the annual electricity charges for a residential customer, based on an inputted volume of electricity used.

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[45] Kost, C., et al. (2013). "Levelized Cost of Electricity Renewable Energy Technologies Study." Fraunhofer Institute for Solar Energy Systems ISE.

[46] PBR refers to a method of regulating distribution prices. PBR dictates to what level prices can increase on an annual basis and that measure is used to forecast distribution rates.

Alberta Electric System Operator (2014). "AESO Transmission Rate Impact Projection (TRIP) Workbook - June 2014.". Retrieved July 24th, 2015, from http://www.aeso.ca/downloads/AESO_2014_Transmission_Rate_Impact_Projection_Workbook_-_Jun_2014.xlsx.

The current cost of rooftop solar panels in Alberta is taken from a report by Kuby Renewable Energy Ltd. (Kuby). Kuby is a solar installer based out of Edmonton.[47]

A forecast of the costs of residential solar panels in Alberta is calculated by decreasing the cost of rooftop solar in Alberta (provided by Kuby) by the rate of cost declines forecasted by a German academic paper[48] and a solar forecast by SunShot.[49]

The German academic paper's (authored by Kost et al.) low scenario for the levelized cost of electricity (LCOE) for rooftop solar panels is 0.098 Euro/kWh[50] falling to 0.055 euros/kWh in 2030[51]. Forecasted values of LCOE are reported in 2013 Euros, and represent the LCOE for plants installed in the listed year[52]. The low scenario forecasts solar costs decreasing by 3.3 percent each year.[53] LCOE is the per kWh cost of building and operating a generating plant. It includes the capital, fuel, operations and maintenance and financing costs associated with the

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[47] Kuby Renewable Energy Ltd. "The Cost of Solar Panels." Retrieved July 7th, 2017, from https://kubyenergy.ca/blog/the-cost-of-solar-panels.

[48] Kost, C., et al. (2013). "Levelized Cost of Electricity Renewable Energy Technologies Study." Fraunhofer Institute for Solar Energy Systems ISE.

[49] US Department of Energy. Retrieved March 28th, 2016, from https://energy.gov/eere/sunshot/sunshot-2030.

[50] Kost, C., et al. (2013). "Levelized Cost of Electricity Renewable Energy Technologies Study." Fraunhofer Institute for Solar Energy Systems ISE.

[51] Ibid.

[52] Ibid.

[53] (0.055/0.098)^(1/17 years) -1 = -0.033

plant.[54] In the case of rooftop solar the fuel and operations and maintenance of the panels are very small.

Sunshot forecasts a much more aggressive decrease in solar costs for residential systems. Sunshot forecasts that solar costs will fall from 18 US cents/kWh in 2016 to 5 US cents/kWh in 2030.[55] This is an 8.7 percent decrease each year.[56]

The cost of solar calculated by Sunshot is larger than Kuby's estimate of a 6 kW rooftop solar system. Kuby estimates that a 6 kW system would cost $17400 CDN in Alberta in 2017. Sunshot forecasts a 5.6 kW residential rooftop solar system will cost $20852 CDN in 2017.[57] Kuby's estimates are adjusted upwards by ten percent to reflect the larger estimates by SunShot.

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[54] US Energy Information Agency (2017). "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017." Retrieved July 18th, 2017, from https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[55] US Department of Energy. Retrieved March 28th, 2016, from https://energy.gov/eere/sunshot/sunshot-2030.

[56] (5/18)^(1/14 years) -1 = -0.087

[57] 2.93 USD/Watt *(1.329 $CDN/$US) * 6000 Watts * (1.02) * (0.875) = $20 852.21

The USD/Watt cost estimate is taken from Fu, R., et al. (2016). "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016." Retrieved February 6th, 2018, from https://www.nrel.gov/docs/fy16osti/66532.pdf. . The US average price of solar modules is used.

The exchange rate is taken from Internal Revenue Agency (2016). "Yearly Average Currency Exchange Rates Translating foreign currency into U.S. dollars." Retrieved November 29th, 2016, from https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates.

The estimate is multiplied by 6000 Watts to calculate the cost of a 6000 Watt system (6 kW). The estimate is inflated to 2017 dollars to match the year that Kuby's estimate was provided. Finally the estimate is decreased by 12.5% as this is what Sunshot forecasts solar costs to decline by in 2017 relative to 2016.

Kuby's adjusted estimate is used for the upfront cost of solar in 2017. Kuby includes cost estimates for different sizes of solar systems. Larger systems have a lower cost on a per kW basis. Kost and Sunshot forecast that the cost of solar will fall over the next thirteen years. Kuby's estimates are decreased each year by the same percentage forecasted in Kost and Sunshot, respectively. The cost of the solar panels is added to the cost of additional electricity, and distribution and transmission charges over twenty-five years. The present value of all costs associated with rooftop solar over a 25 year period is calculated for each year of the forecast. This is compared to the present value of the full costs of consuming electricity with no solar panels (also over a 25 year period). If the present value of the cost of consuming electricity from the grid is greater than the present value of the costs of consuming electricity using a solar panel, the consumer will have an incentive to substitute to solar (section 5.2.10 explains how the incentive to wait can impact the substitution date). If not, the consumer will continue to use grid electricity. The data on cost of electricity and distribution and transmission charges is taken from the AESO TRIP workbook and the TRP update.

5.2 Economic Drivers of Rooftop Solar Adoption

A household's incentive to install rooftop solar panels is determined by the cost of installing and purchasing solar panels, electricity prices on the grid, the level and structure of transmission and distribution tariffs, the size of the rooftop solar system installed by the customer and the capacity factor of those systems, and the nominal discount rate of the customer.

5.2.1 Cost of solar panels and installation.

The cost of solar panels has a big impact on the date of substitution. Kuby's estimate of Alberta's residential solar costs is used as a base with Kost et al. low forecast's rate of cost decrease. The cost of solar in Alberta is forecasted out to 2030.

Sunshot provides an alternative rate of cost decrease to Kost. Sunshot is an initiative led by the US Department of Energy, that aims to make solar a low cost energy source. The organization forecasts residential solar costs falling to 5 US cents per kWh in 2030 (real American dollars) from the current 18 cents per kWh.[58] The Sunshot forecast is used to test what would happen if solar costs fell dramatically over the next thirteen years.

Sunshot's solar costs decline more quickly than Kost's low forecast. The rate of decrease has a big impact on the date that Fortis, Enmax, ATCO and Epcor customers find it economical to switch to solar.

Soft costs are an important area for cost reductions for residential solar. Soft costs include labour, design and engineering, permitting and interconnection, and customer acquisition.[59] Sixty four percent of residential solar costs are categorized as 'soft'.[60]

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[58] US Department of Energy. Retrieved March 28th, 2016, from https://energy.gov/eere/sunshot/sunshot-2030.

[59] GTM Research (2016). "PV-Price-Brief-H1-2016-brochure." Retrieved November 9, 2016, from https://forms.greentechmedia.com/Extranet/95679/forms.aspx?msgid=f5a5261f-aa0c-4795-9a68-6b20b4d9bcd0&LinkID=CH00095679eR00000448AD&Source=sidebar.

Soft cost reductions for residential solar have the biggest impact on overall system costs. The rate of decrease in residential solar costs depends on how quickly solar soft costs fall in Alberta.

5.2.2 Size of solar system.

The size of a solar system has a big impact on the cost of the solar panels per kW of capacity. Larger systems achieve greater economies of scale which reduces the cost per kW of capacity installed.

The average customer for Fortis could install a 5 kW system and offset all of their electricity consumed with solar energy (approximately 564 kWh per month).[61] A high use customer in Fortis area would consume 1269 kWh's per month would need to install a 11 kW system to offset all of their electricity.[62] The appendix shows this calculation for ATCO's 3rd quintile.

The price difference per kW of capacity between a 5 kW and a 11 kW system is substantial. In a recent report produced by Kuby renewables a 6 kW system costs approximately \$2.9/W, and a

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[60] GTM Research (2016). "Solar PV Prices Will Fall Below \$1.00 per Watt by 2020." Retrieved November 9th, 2016, from https://www.greentechmedia.com/articles/read/solar-pv-prices-to-fall-below-1.00-per-watt-by-2020.

[61] See Table 9 in Chapter 6. 564 kWh per month becomes 6768 kWh per year. A 5.088 kW solar system is capable of producing 1330 kWh/kW of capacity installed (see section 5.5.4 for discussion of capacity factor). By multiplying 1330 kWh/kW by 5.088 kW of capacity, you get 6768 kWh of solar energy produced per year.

[62] See Table 9 in Chapter 6

10 kW system costs approximately $2.5/W. By increasing the size of the system from 6 kW to 10 kW, the average cost decreases by sixteen percent.[63]

Given that residential customers can save money by installing larger systems, they will be incented to install the largest systems possible under the microgeneration legislation. Under the microgeneration legislation, Residential customers can only install systems that create net zero consumption over the course of one year. A result of the paper is that if residential customers have the economic incentive to install solar, they will systems large enough to offset all of their electricity consumption over the course of one year. This assumption is applied to all residential customer in Alberta.

An average residential rooftop system will range from 4 kW to 6 kW.[64] A 4 to 6 kW system covers the electricity use of the average electricity user in most areas of Alberta. Larger systems are possible, but the size of rooftop solar systems is constrained by the amount of rooftop available.

A typical 0.23 kW solar panels is 1.652 meters squared.[65] The average floor space area for a new home in 2012 in Canada was 181 meters squared.[66] If the average household rooftop is 90.5

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[63] Kuby Renewable Energy Ltd. "The Cost of Solar Panels." Retrieved July 7th, 2017, from https://kubyenergy.ca/blog/the-cost-of-solar-panels.

[64] Ibid.

[65] Affordable Solar. "Conergy P 230PA, 230W Solar Panel." Retrieved November 18th, 2016, from http://store.affordable-solar.com/store/discontinued-unavailable-solar-panels/Conergy-Silver-P230PA-230-watt-Solar-Panel.

meters squared and it is entirely covered with 0.23 kW solar panels, then it would be possible to install 55 panels. That's a 12.7 kW system.[67]

Households are also constrained by the amount of south facing rooftop space. The north facing portion of roofs does not provide the same quality of sunlight and it may not make sense to install solar panels on these portions of rooftops. On average, half of residential roofs are south facing and have good exposure to the sun. The capacity factors used for all regions are for south facing panels (sourced from Natural Resources Canada).[68] This means that the capacity factor used for larger systems (greater than 6 kW) are optimistic because it is likely that some panels on larger systems would be north facing.

This paper assumes that the average installation in Alberta will be between 4-6 kW. This is in line with Kuby's estimate of the average rooftop solar capacity size.

This paper assumes that installing a system larger than 15 kW is unlikely in Alberta for the average household. There are examples of systems larger than 15 kW in Alberta.[69] Four percent

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[66] Wilson, L. "How big is a house? Average house size by country." Retrieved December 1st, 2016, from http://shrinkthatfootprint.com/how-big-is-a-house.

[67] 90.5 meters squared / 1.652 meters squared per panel = 55 panels
55 panels * 0.23 kW per panel = 12.7

[68] Natural Resources Canada (2017). "Photovoltaic and solar resource maps." Retrieved June 12th, 2017, from https://www.nrcan.gc.ca/18366?lang=e&m=r.

[69]Skyfire Energy (2017). "Longview Alberta." Retrieved August 10th, 2017, from http://www.skyfireenergy.com/case-study-home/15-86kw-grid-tied-solar-power-system-longview-alberta/.

Skyfire Energy shows examples of residential systems as large as 25 kW. These are outliers.

of Enmax customers consume enough electricity to be allowed to install solar systems larger than 15 kW (>1600kWh per month).[70] A subset of these customers would have enough roof space to allow them to install systems larger than 15 kW.

5.2.3 Volume of electricity.

Volume of electricity consumed by a household has an impact on the incentive to install solar panels. Households with a higher volume of consumption can install larger solar systems, which achieve greater economies of scale. The microgeneration regulation only allows customers to install systems that lead to net zero or positive electricity consumption from the grid.

A distribution of average monthly residential electricity use in Calgary is used to separate Alberta's residential customers based on average electricity use. The paper simplifies the distribution to 5 quintiles. The 5th quintile consumes the most electricity per month. The 4th quintile consumed the second most electricity per month. The 1st quintile consumes the least electricity per month. The top quintile of Enmax consumers consumed 1043 kWh's monthly, on average, and the bottom quintile consumed 223 kWhs monthly, on average.[71]

Figure 1 - Distribution of Enmax Customers by Monthly Electricity Consumption

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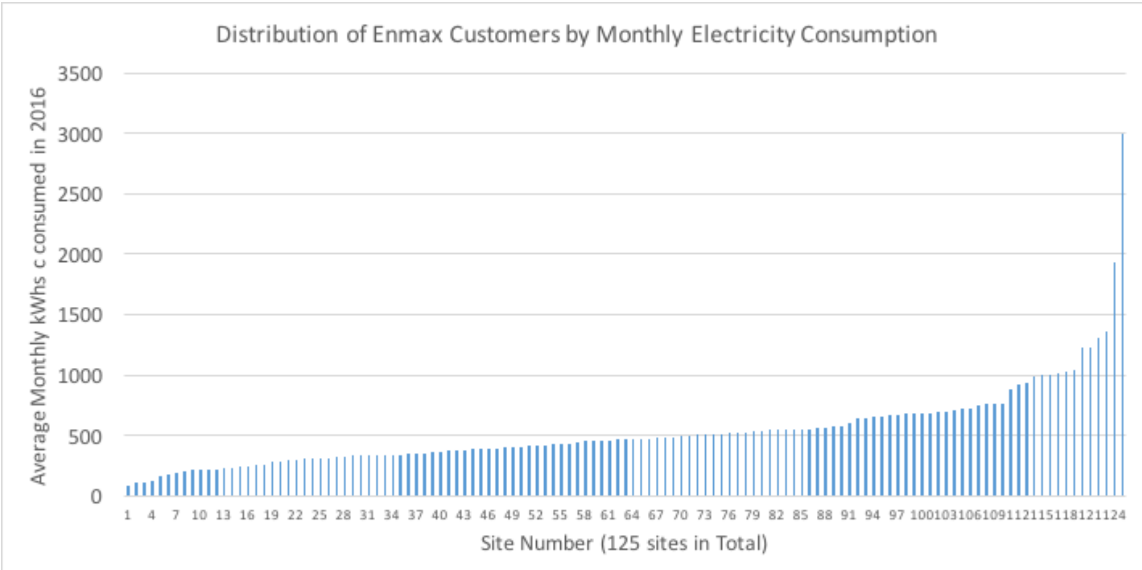
[70] See Figure 1 in Chapter 5 for distribution of electricity users in Alberta

[71] The quintiles are based on a distribution provided by Enmax and the average electricity use list by the MSA. Enmax's distribution is adjusted to match the average electricity use listed by the MSA.

Market Surveillance Administrator (2016). "2016-06-30 MSA Retail Market Statistics." Retrieved November 29th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-06-30_MSA_retail_market_statistics.xlsx.



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The quintiles of electricity are used to separate all of Alberta's residential customers into five groups. The 5th quintile (largest consumption) is most likely to install large systems. These systems achieve the best economies of scale and have the lowest cost of solar per kW of capacity. The following quintiles would follow after the 5th as solar costs decrease over time for all customers, and transmission costs increase over time. The substitution dates of each quintiles for each respective Distribution Facility Owner (DFO) is covered in Chapter 6.

5.2.4 Capacity factor.

Capacity factor refers to how many hours in a year a rooftop solar panel produces electricity. Natural Resources Canada provides the number of hours of electricity produced by solar panels

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[72] The distribution of Enmax customers was provided by ENMAX Power Corporation in a data request.

for all provinces across Canada.[73] The capacity factor is stated in kWh of production over one year per kW of capacity installed. The capacity factor for Grand Prairie (1186 kWh/kW) is used for ATCO's service area. The capacity factor for Calgary (1290 kWh/kW) and Edmonton (1247 kWh/kW) are used for Enmax and Epcor's service areas. Medicine Hat's Capacity factor (1330 kWh/kW) is used for Fortis. 1186 kWh per kW of capacity means that the solar panel will produce electricity in 13.5 percent of hours over the course of one year.[74] Medicine Hat's capacity factor is 15 percent.[75]

5.2.5 Solar subsidy.

In June 2017, the Alberta government announced 36 million dollars in funding for residential and commercial rooftop solar panels.[76] The program provides $750/kW of solar installed as a rebate to residential customers. Assuming that half of the programs' revenue goes to participants that are residential and half goes to commercial participants, this will lead to 4000 6 kW residential solar systems being rebated.[77] Alberta had 1,442,311 residential customers in 2016.[78]

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[73] Natural Resources Canada (2017). "Photovoltaic and solar resource maps." Retrieved June 12th, 2017, from https://www.nrcan.gc.ca/18366?lang=e&m=r.

[74] 1186 / 8760 = 13.5%. There are 8760 hours in one year.
[75] 1330 / 8760 hours = 15 %.
[76] Alberta Government (2017). "Rebates to help Albertans tap solar resources." Retrieved July 20th, 2017.

[77] 18 million / ($750/kW*6kW system) = 4000 systems.

Energy Efficiency Alberta. "Energy Efficiency Alberta Solar Program." Retrieved March 30th, 2018, from https://www.efficiencyalberta.ca/solar/.

[78] Market Surveillance Administrator (2016). "2016-06-30 MSA Retail Market Statistics." Retrieved November 29th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-06-30_MSA_retail_market_statistics.xlsx.

The rebate would impact 0.2 percent of residential customers in the province.[79] For this reason, the impact of the program is not considered. It is not large enough to make a significant impact on rooftop solar adoption in the province.

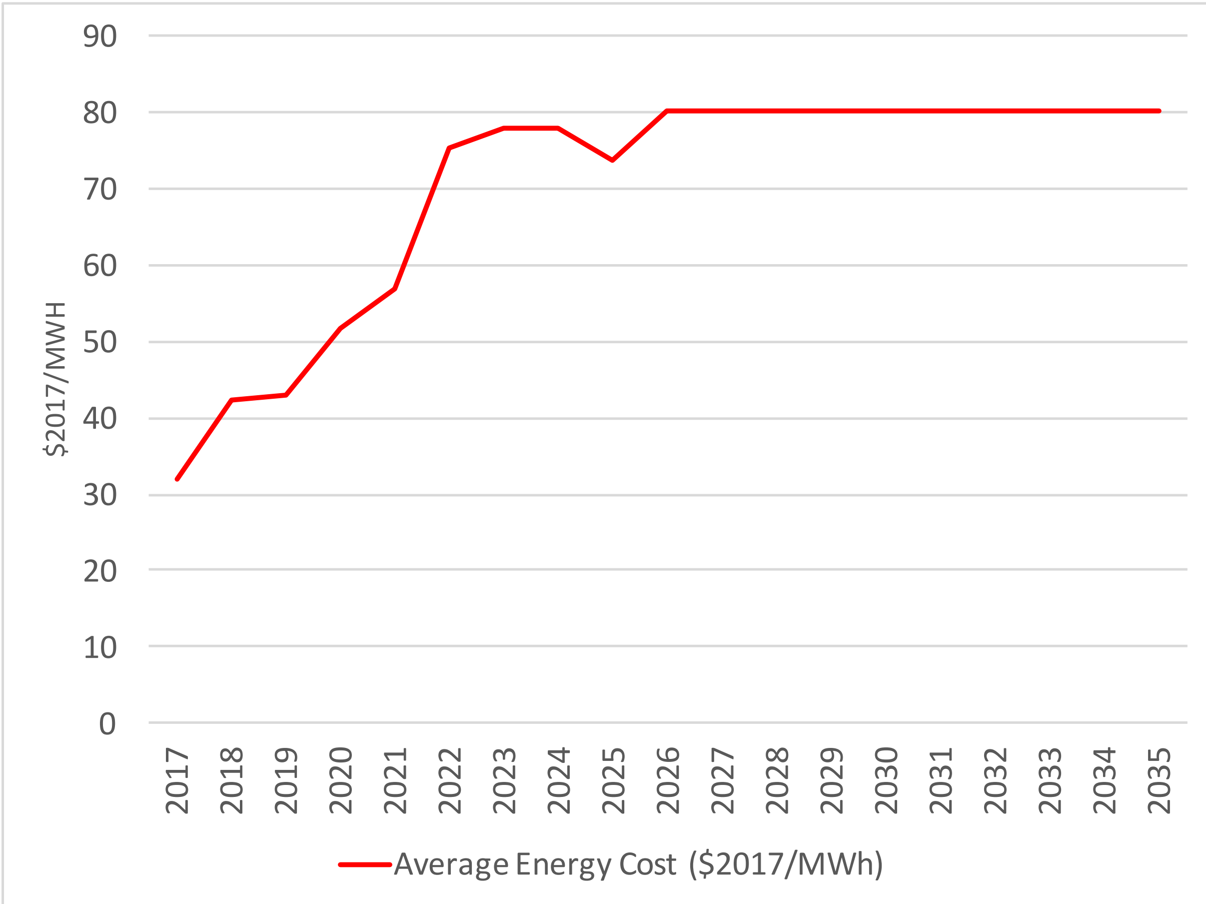
5.2.6 Electricity prices.

The electricity price forecast is taken from the AESO's transmission rate projection. The forecast is the average cost of energy developed by EDC associates. EDC's forecast ends in 2025. The forecasted price for 2025 is continued from 2025 to 2055 using the forecasted LCOE of a conventional gas plant in 2022.[80] Average energy cost refers to the price of electricity in the wholesale electricity market. Historically pool price has been the price of electricity in the wholesale electricity market. Alberta will be transitioning to a capacity market in 2021. In the capacity market, the price of electricity will be split between the capacity market and the energy market. The average energy cost forecast by EDC after 2021 when the capacity market is implemented is the total cost of electricity in both the capacity market and the energy market. The average energy cost forecast by EDC prior to 2021 is the pool price.

Figure 2 - Alberta Average Energy Cost Forecast

[79] 4000/1442311 = 0.2%

[80] US Energy Information Agency (2017). "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017." Retrieved July 18th, 2017, from https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.



[81]

The electricity price forecast in Figure 2 needs to be converted to the retail rate of electricity that residential customers pay for electricity. The retail rate of electricity is the rate that electricity retailers charge residential customers for electricity. Residential customers can choose from two different groups of retail rates. There is the regulated rate option (RRO) and there are competitive contracts.

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[81] Data for graph taken from AESO (2017). "Transmission Rate Projection." Retrieved February 13th, 2017, from https://www.aeso.ca/assets/Uploads/TRP-Factsheet-WEB.PDF.

The Regulated Rate Option (RRO) is based on pool prices. [82] Every month a new RRO is calculated for each retailer that offers the RRO. The RRO for a given month is calculated using a load forecast and the forward electricity prices.[83] The RRO includes a risk margin. The risk margin covers the retailer for volume risk, price risk, credit risk and unaccounted for energy and losses. [84] On top of the risk margin, the RRO includes a reasonable rate of return to the retailer for providing electricity services.[85]

Alberta's residential customers can also sign a contract to receive electricity from a competitive retailer. The competitive contracts are similar to the RRO in that retailers will purchase electricity from the power pool and sell it to residential customers with an added premium for risk and a rate of return for the retailer.[86]

The risk margin added on the RRO and the competitive contracts means that the retail rate of electricity is typically higher than the pool price. Figure 3 shows the pool price and the RRO for Enmax in 2013.

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[82] Alberta Utilities Commission. "Alberta's energy market." Retrieved September 28, 2016, from http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx.

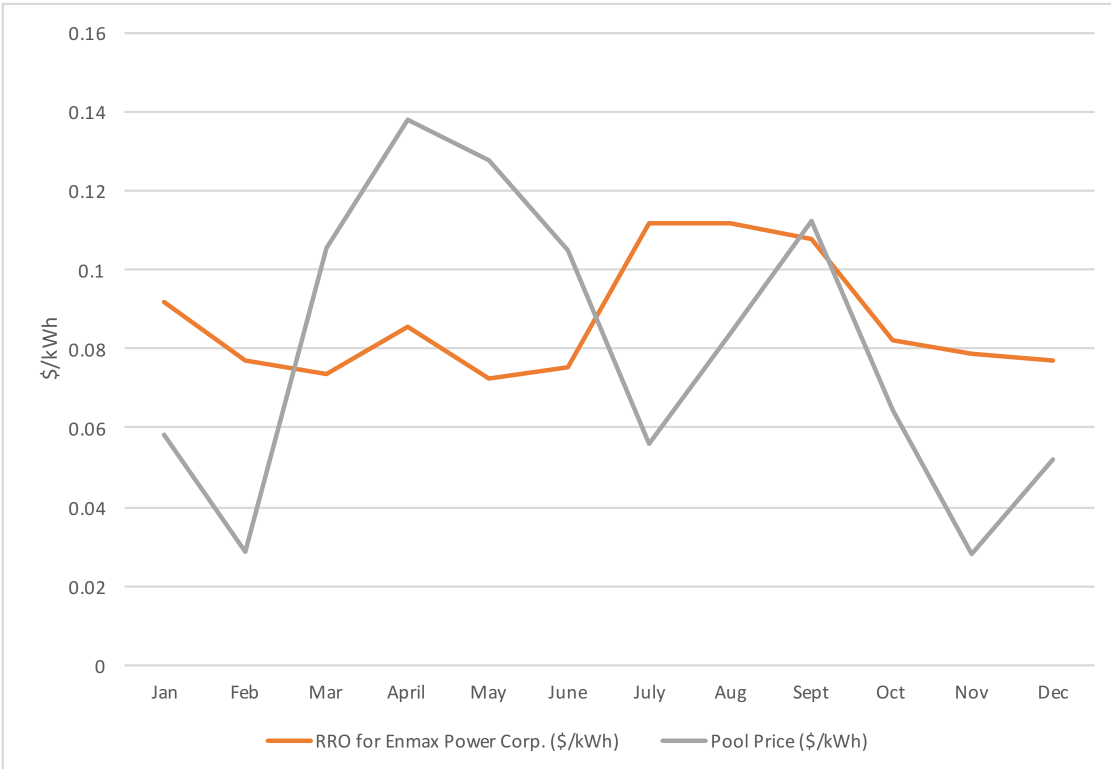
[83] Government of Alberta. "ELECTRIC UTILITIES ACT REGULATED RATE OPTION REGULATION." Retrieved September 28th, 2016, from http://www.qp.alberta.ca/documents/Regs/2005_262.pdf.

[84] Ibid.

[85] Ibid.

[86] Alberta Utilities Commission. "Electricity." Retrieved September 29th, 2016, from http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Pages/Electricity.aspx.

Figure 3 - RRO versus Pool Price[87]



On average, Enmax Power Corp's RRO was 39 percent higher than the pool price in 2013. This difference can also be observed in other years. In 2017 Enmax Power Corp. RRO was 69 percent higher than pool price.

The ratio between pool price and the RRO for Enmax for 2013 is applied to all years of the electricity price forecast to convert the pool price to the retail rate of electricity for all DFO

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[87] RRO for Enmax Power Corp. is sourced from Utilities Consumer Advocate. "Historic Rates." Retrieved March 18th, 2018, from https://ucahelps.alberta.ca/historic-rates.aspx.

The Pool Price is source from Alberta Electric System Operator. Retrieved March 18th, 2018, from http://ets.aeso.ca/.

service areas. 2013 is used because the pool price in 2013 is at a similar level to the pool price forecast. The average pool price in 2013 was 87 dollars (inflated to 2017 dollars).[88] The average pool price forecast from 2017 to 2055 is 70 dollars (deflated to 2017 dollars). The assumption is that the ratio between the RRO and the pool price in 2013 will be similar from 2017 to 2055.

Figure 4 shows the forecast of the retail rate of electricity and the forecast of the average energy cost. Applying the ratio between the RRO and the pool price in 2013 to all forecast years produces a retail rate that is 39 percent higher than the average energy cost (pool price prior to 2021 and capacity plus energy 2021 an onwards).

In 2018 the Alberta government implemented a cap on the RRO in Alberta. The cap means that if the RRO cannot rises above 6.8 cents/kWh, the government will cover off the difference with tax revenues.[89] The paper ignores the cap in its price forecast because there is some political uncertainty surrounding the price cap. Also, the uncapped RRO used in the paper reflects the price of electricity from a social perspective. While the government may cap the level of electricity prices, the cost of the electricity is still being borne by tax payers and this cost is included in the paper.

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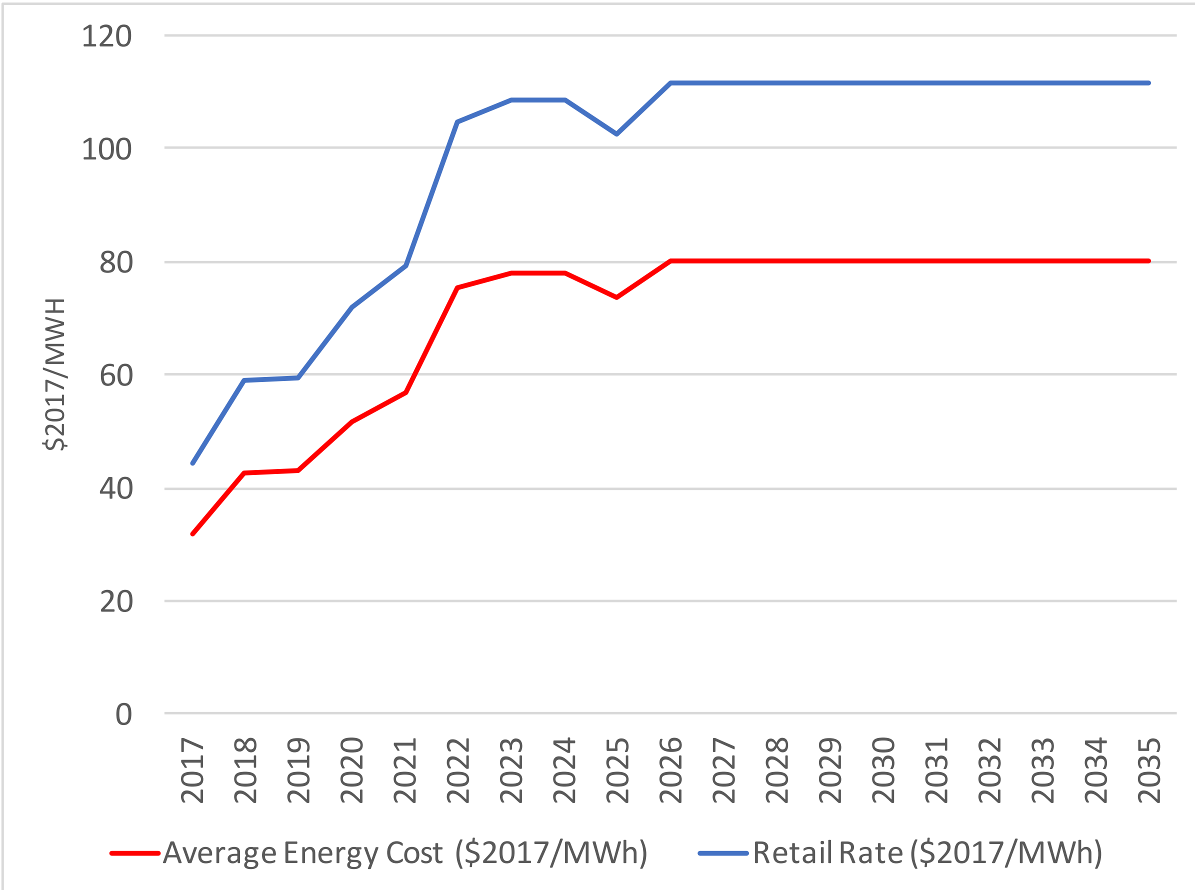
[88] Alberta Electric System Operator. Retrieved March 18th, 2018, from http://ets.aeso.ca/.

[89] Alberta Government (2016). "Price cap to protect consumers from volatile electricity prices." Retrieved May 20th, 2018, from https://www.alberta.ca/release.cfm?xID=4487283D35A59-070B-5A1F-76A7FB63D2CA149D.

Figure 4 - Retail Rate versus Average Alberta Energy Cost Forecast



Changing the electricity prices that are forecasted in the TRP does have an impact on the date of substitution for residential customers. ATCO's 4th quintile is forecasted to substitute to solar in 2017. The 4th quintile refers to a subsection of ATCO customers. The 2017 substitution date assumes that electricity prices will recover to $79/MWh in 2030 (real 2017 Canadian dollars). If electricity prices stay at the level seen in the first half of 2016 ($16.57/MWh)[90], ATCO

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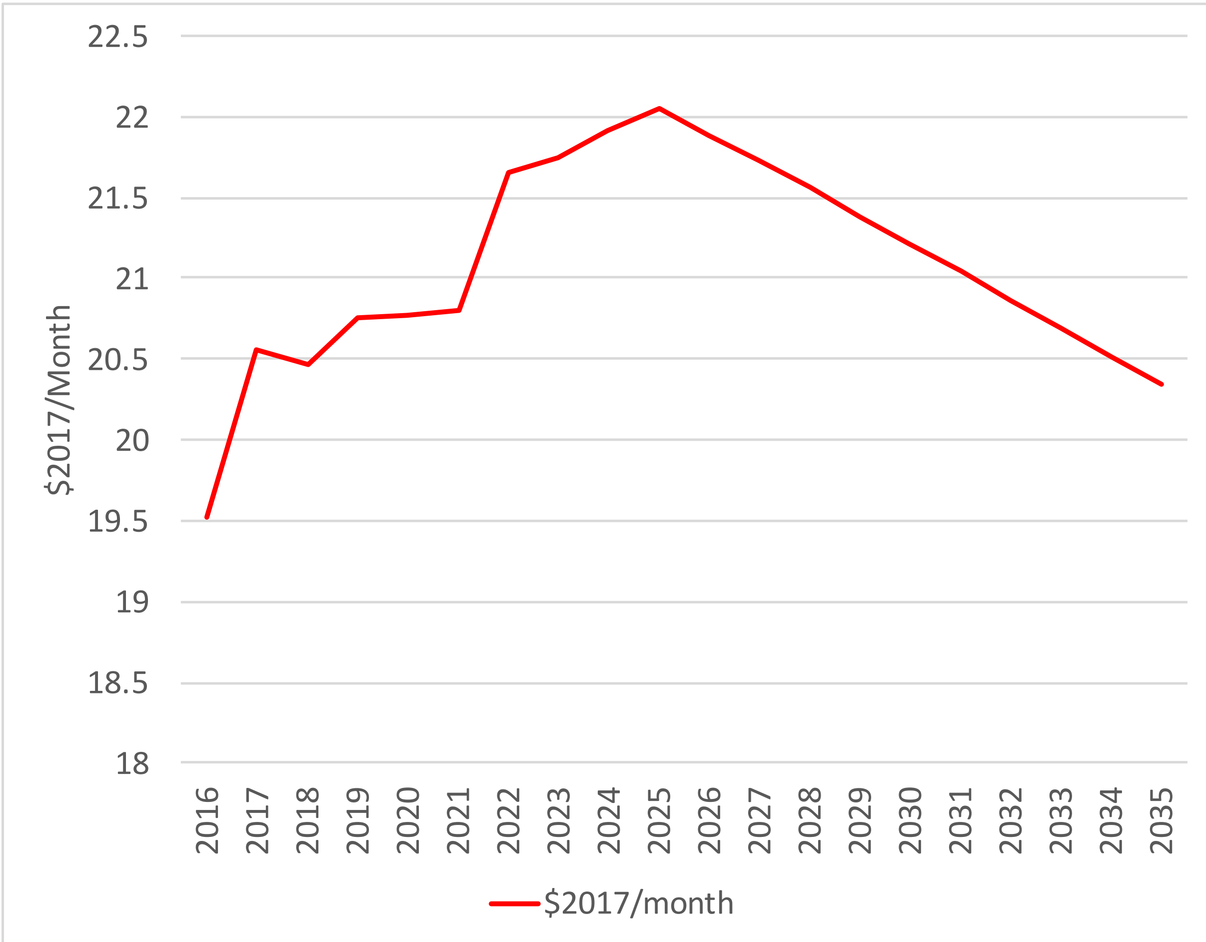
[90] Varcoe, C. (2016). "Varcoe: Alberta's power market in turmoil as prices hit 20-year lows and demand falls." Retrieved November 10th, 2016, from http://calgaryherald.com/business/energy/varcoe-albertas-power-market-in-turmoil-as-prices-hit-20-year-lows-and-demand-falls.

customers' 4^{th} quintile substitution to solar will be pushed out to 2030. While it is unlikely that prices will reach that level again, this shows the impact that low electricity prices can have on solar adoption.

5.2.7 Level and structure of transmission and distribution tariffs.

Transmission charges will increase significantly over the next five years, peaking in 2025. This is due to many new transmission projects scheduled to be built over the next five to ten years. The increase in transmission costs will increase the incentive to install rooftop solar.

Figure 5 - Monthly Residential Transmission Charge (600 kWh)



91

The structure of transmission and distribution tariffs has a big impact on the incentive to install solar. Customers in distribution areas with high distribution and transmission (ATCO) will substitute to solar more quickly. This is because solar customers can save a substantial amount

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[91] Data for graph taken from AESO (2017). "Transmission Rate Projection." Retrieved February 13th, 2017, from https://www.aeso.ca/assets/Uploads/TRP-Factsheet-WEB.PDF.

on transmission and distribution cost. The 2017 distribution and transmission tariffs for ATCO, Fortis, Enmax and EPCOR are as follows.

Table 1 - Residential Transmission and Distribution Charges in Alberta

	Distribution Variable Charge (cents/kWh)	Distribution Fixed Charge (cents/day)	Transmission Variable Charge (cents /kWh)	Sum of Distribution and Transmission Variable Charge (cents/KWh)
ATCO Electric[92]	7	120	4	11
Fortis Alberta[93]	2	70	4	6
EPCOR[94]	0.9	60	3	3.9
Enmax[95]	1	50	2	3

ATCO Electric customers have the highest variable charge for transmission and distribution combined, followed by Fortis Alberta, EPCOR and Enmax. The variable charge creates savings

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[92] ATCO Electric (2017). "Price Schedule Index." Retrieved March 25th, 2018, from http://www.atcoelectric.com/Rates/tariffs/Documents/2017-01-01%20AE%20Price%20Schedules.pdf.

[93] Fortis Alberta (2017). "RATES, OPTIONS, AND RIDERS SCHEDULES." Retrieved March 25th, 2018, from https://fortisalberta.com/docs/default-source/default-document-library/2017-rates-options-and-riders.pdf?sfvrsn=10.

[94] EPCOR (2017). "Transmission Access Service Tariff Effective January 1, 2017." Retrieved August 10th, 2017, from https://www.epcor.com/products-services/power/rates-tariffs-fees/Documents2/SystemAccessServiceTariff-2017.pdf.

[95] Enmax Power Corp. (2017). "Distribution Tariff Rate Schudule." Retrieved 2018, March 25th, from https://www.enmax.com/ForYourBusinessSite/Documents/2017-07-01-DT-Rate-Schedule.pdf.

for a solar user because transmission and distribution are charged based on the net electricity consumed. Rooftop solar decreases the net electricity consumed off the grid and decreases the variable charge for residential solar customers.

ATCO Electric customers will be the first to experience an economic incentive to install solar in the province, because they have the highest variable charges for distribution and transmission. ATCO customers experience the highest transmission and distribution savings from installing solar, under the current tariff design.

5.2.8 Discount rate.

Residential customers compare the cost of consuming electricity from the grid to the cost of consuming electricity with a rooftop solar panel. The system that has the lower cost over the life of the solar panel is the technology of choice.

Rooftop solar has a large upfront cost. Savings from solar occur after the investment in the solar panels is made. Each month, the consumer saves on electricity charges, transmission charges and distribution charges.

The customer's valuation of savings over time plays a big role in determining how attractive a solar investment is. If savings in the future are much less valuable to a consumer compared to savings today, the desirability of rooftop solar decreases.

The valuation of savings over time is called the discount rate. The lower the discount rate, the more desirable rooftop solar is to a consumer. Decreasing the nominal discount rate from 8.75 percent to 4.8 percent changes the adoption rate for the 1st quintile of ATCO customer from 2022 to 2017.

The investment period for a solar panel is long. Kost estimates that a rooftop solar panel's life is 25 years. The discount rate over a 25 year period is estimated using current mortgage rates over the same period. Royal Bank currently advertises an 8.75% annual percentage rate (APR), fixed over 25 years.[96] APR is the annual borrowing cost.[97]

The Royal Bank's APR is a high estimate of a residential customer's discount rate. The APR represents the bank's opportunity cost of lending money to a residential customer. The bank is willing to lend money to residential customers at 8.75 % because that rate is equal to or better than any other returns the bank could earn with the same money. Depending on a residential customer's other investment opportunities, they may have a higher or lower discount rate.

Kuby Renewables, a rooftop installer based out of Edmonton, estimates that the nominal discount rate for residential customers in Alberta is 4.8%.[98] Kuby's estimate is based on different

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[96] Royal Bank (2017). "Fixed Mortgage Rates." Retrieved August 14th, 2017, from http://www.rbcroyalbank.com/mortgages/mortgage-rates.html.

[97] Investopedia. "Annual Percentage Rate - APR." Retrieved July 17th, 2017, from http://www.investopedia.com/terms/a/apr.asp.

[98] Kuby Renewable Energy Ltd. "The Cost of Solar Panels." Retrieved July 7th, 2017, from https://kubyenergy.ca/blog/the-cost-of-solar-panels.

assumptions concerning what rate of return a residential customer could earn if they invested their money in something other than rooftop solar panels. This paper tests both discount rates to demonstrate the impact of discount rates on rooftop solar adoption. The 4.8 % to 8.75% range is similar to other studies on rooftop solar adoption. A study on the adoption of rooftop solar panels in Germany test 4% to 8% nominal discount rates for residential customers.[99] This shows that an 8.75% discount rate is a high estimate for residential customers and 4.8% is a low estimate relative to other jurisdictions.

The paper also tests a higher discount factor than the reference case. A 12.75% nominal discount rate is tested as an additional sensitivity. It is possible that residential customers have a higher discount rate when considering investing in solar. There are risks associated with installing solar, like the future electricity price changing or the expected future transmission prices changing. If the residential customer perceives the risk associated with solar to be high, they may want a higher return on the investment to cover that risk. The 12.75% nominal discount rate tests the impact of solar being a higher risk investment and requiring a higher return as a result.

A 25 year time period and a 8.75 percent nominal discount rate is used for all present value calculations. Sensitivities analysis with a 4.8% and 12.75% discount rate are used to show the impact it would have on the adoption of rooftop solar panels.

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[99] Edinger, R. (1999). Distributed Electricity Generation with Renewable Resources: Assissing the economics of photovoltaic technologies in vertically integrated and in restructured energy markets, Tectum Verlag.

5.2.9 Present value calculation.

Below is an example of the tables used to calculate the present value of the full costs of rooftop solar and the present value of the full costs of consuming electricity from the grid. These tables are taken from the calculation of the 3rd quintile of ATCO customers.

Table 2 - Annual Bill of ATCO Customer (3rd Quintile)

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I
		Solar	non-solar					
	Monthly Consumption (kWh)	0	508					
Unit*	Transmission charge $/kWh	Distribution Charge (fixed) $/month	Distribution charge variable $/kWh	Administration Fee $/month	Local Access Fee $/ month	Energy Cost $/month	Annual Electricity cost (Grid Electricity) $/year	Annual Electricity Cost (Grid electricity supplemented with solar) $/year
2017	0.035	29.8	0.1	10	5	22	1417	530
2018	0.037	30.8	0.1	10	5	30	1543	543
2019	0.037	31.8	0.1	10	5	30	1573	556
2020	0.037	32.9	0.1	10	5	37	1681	571
2021	0.037	33.7	0.1	10	5	40	1747	582
2022	0.038	34.8	0.1	10	5	53	1935	598
2023	0.039	35.9	0.1	10	5	55	1997	613
2024	0.039	37.1	0.1	10	5	55	2028	628
2025	0.040	38.0	0.1	10	5	52	2018	639
2026	0.040	39.2	0.1	11	5	57	2105	655
2027	0.039	40.4	0.1	11	5	57	2134	671
2028	0.039	41.6	0.1	11	5	57	2164	686
2029	0.039	42.8	0.1	11	5	57	2195	702
2030	0.039	44.0	0.1	11	5	57	2225	718
2031	0.038	45.5	0.1	11	5	57	2263	738
2032	0.038	46.8	0.1	11	5	57	2294	754
2033	0.038	48.0	0.1	11	5	57	2326	770
2034	0.037	49.5	0.1	11	5	57	2362	789
2035	0.037	51.0	0.1	12	5	57	2400	808
2036	0.037	52.5	0.1	12	5	57	2439	828
2037	0.037	54.1	0.1	12	5	57	2482	849
2038	0.037	55.8	0.1	12	5	57	2525	870
2039	0.037	57.5	0.1	12	5	57	2571	892
2040	0.037	59.2	0.1	12	5	57	2617	914
2041	0.037	61.0	0.1	12	5	57	2665	938
2042	0.037	62.8	0.1	12	5	57	2714	961
2043	0.037	64.8	0.1	13	5	57	2765	986
2044	0.037	66.7	0.1	13	5	57	2817	1011
2045	0.037	68.7	0.2	13	5	57	2871	1037
2046	0.038	70.8	0.2	13	5	57	2926	1064
2047	0.038	73.0	0.2	13	5	57	2983	1091
2048	0.038	75.2	0.2	13	5	57	3041	1119
2049	0.038	77.5	0.2	13	5	57	3102	1148
2050	0.038	79.8	0.2	14	5	57	3164	1178
2051	0.038	82.2	0.2	14	5	57	3228	1209
2052	0.038	84.7	0.2	14	5	57	3294	1241
2053	0.038	87.3	0.2	14	5	57	3361	1273
2054	0.038	89.9	0.2	14	5	57	3431	1307
2055	0.038	92.6	0.2	14	5	57	3503	1342

Note: all values have been adjusted by a 2% inflation rate to set them at 2017 dollars. The PV calculation in Table 3 further adjusts these values using a real discount rate (6.6%).

Table 2 is the first step of calculating the present value of using grid electricity and the present value of grid electricity supplemented with solar electricity. Grid electricity means that the customer only sources their electricity from the grid. Grid electricity supplemented with solar electricity means that the customer has installed a solar panel on their house. The yellow boxes show the average monthly kWhs consumed by the average ATCO customer in the 3rd quintile. The calculation assumes that solar customers install solar panels that are large enough to offset all of their electricity. Solar customers consume zero electricity from the grid on a net basis and non-solar customers consume 508 kWhs per month.

The transmission, variable distribution charge, and energy price are multiplied by the kWhs consumed for solar and non-solar customers. Since solar customers consume zero electricity on a net basis, they do not pay for transmission, energy, or the variable portion of the distribution charge. The fixed portion of the distribution charge, the administration fee, and local access fee are fixed charges that do not depend on the kWhs consumed. This means that both solar and non-solar customers are charged for these services. The annual electricity cost (grid electricity) – column H - is the annual cost of consuming electricity from the grid for customers in the 3rd quintile of ATCO's service area. The annual electricity cost (grid supplemented with solar) – Column I - is the annual cost of consuming electricity from the grid for a customer in the 3rd quintile of ATCO's service area that has installed a solar panel to offset all of their electricity consumption. This is the fixed charges that the solar customer must pay to use the grid.

All values in Table 2 are real 2017 dollars. A two percent inflation rate was used for all years. The real variable transmission charge is forecast to increase up to 2026. After 2026 the transmission charge is forecast to decrease as a result of fewer transmission projects. The forecast for transmission charges from the AESO only goes up to 2035. The years after 2035 use the average growth rate from 2017 to 2035 to forecast the transmission charge. The average annual growth rate of transmission charges have increased on a nominal basis from 2017 to 2035 by 2.23 percent. This growth rate is applied to the forecast for 2036 to 2055.

The fixed and the variable distribution charge as well as the administration fee only have a forecast up to 2033 in the TRIP workbook. The forecast from 2034 to 2055 for the fixed distribution charge uses the average annual growth rate of the fixed distribution charge from 2017 to 2033 (5%). The forecast for the variable portion of the distribution charge and the administration fee use the same logic.

A sensitivity analysis is done in Chapter 6 to test what would happen to the incentive to install solar if the cost of transmission and distribution do not grow from 2030 to 2055 on a real basis.

The nominal value of the local access fee is forecast using the CPI index as the growth rate. This means that on a real basis the local access does not change in the forecast.

Column H and I are used to calculate the present value of electricity costs for solar and non-solar customers in Table 3.

Table 3 – Present Value Calculation of ATCO Customers (3rd Quintile)

Column A	Column B	Column C	Column D	Column E	Column F	Column G
Year	Present Value of Electricity costs (grid option)*	Present Value of Electricity costs (grid supplemented with solar)*	Solar Panel Cost*	Present Value total Non-solar*	Present Value Total Solar*	Difference*
2017	$25,669	$8,505	$18,369	$25,669	$26,873	($1,205)
2018	$26,440	$8,709	$17,755	$26,440	$26,464	($24)
2019	$27,139	$8,918	$17,162	$27,139	$26,080	$1,059
2020	$27,863	$9,132	$16,589	$27,863	$25,721	$2,142
2021	$28,532	$9,350	$16,034	$28,532	$25,385	$3,147
2022	$29,185	$9,577	$15,499	$29,185	$25,075	$4,110
2023	$29,695	$9,808	$14,981	$29,695	$24,789	$4,906
2024	$30,185	$10,044	$14,480	$30,185	$24,524	$5,660
2025	$30,686	$10,286	$13,997	$30,686	$24,283	$6,404
2026	$31,245	$10,538	$13,529	$31,245	$24,067	$7,178
2027	$31,763	$10,797	$13,077	$31,763	$23,874	$7,889
2028	$32,296	$11,063	$12,640	$32,296	$23,703	$8,593
2029	$32,848	$11,337	$12,218	$32,848	$23,555	$9,293
2030	$33,419	$11,620	$11,810	$33,419	$23,430	$9,990
			* All costs are stated in 2017 Canadian Dollars			

In Table 3 Column B is the present value of 25 years of electricity costs for a customer only using electricity from the grid. The present value calculation uses an 6.6% real discount rate. The year 2018 in column B in Table 3 is the sum of the annual electricity costs from Table 2 Column H from 2018 to 2042. The real dollar value of each year is discounted by the real interest rate (6.6%). This gives the time value of money over 25 years of all electricity costs starting in 2018.

Column C in Table 3 is the present value of electricity costs for a customer with a solar panel. This follows the same method as Column B. It is the fixed distribution charges, administration charges and local access fee shown in the previous table discounted back using the real discount rate. The solar panel cost is the cost of installing a 5 kW system in 2017 dollars. The 6.6% real discount rate is not applied to the cost of the solar panel because it is assumed that the full cost of the solar panel is incurred in the first year. The cost of installing solar panels falls each year due to the declining cost of solar. Column E is the same as Column B. Column F is Column C plus Column D. Column G subtracts the present value of the cost of using grid electricity supplemented with solar (column F) from the present value of the cost of using grid electricity (Column E).

If the value in Column G is positive then the customer has an incentive to install solar. A positive number in Column G means that the cost of solar over the 25 year investment is less than the cost of using electricity exclusively from the grid. This means that the customer can save money on their residential electricity costs by installing solar. Even if a customer can save money in a given year by installing solar, they may choose to wait several years to accrue even larger savings. Section 5.2.10 explains the incentive to wait to install solar for a residential customer and how this impacts the year that solar is installed.

The total present value of installing solar falls each year, due to the decreasing cost of solar installations. The present value of using grid electricity increases due to increasing distribution and transmission tariffs and the increasing price of electricity.

5.2.10 Incentive to wait.

If solar costs decline quickly enough, customers may have an incentive to wait several years to take advantage of the lower solar cost. This is because the solar cost decline and the resulting returns from waiting more than compensates the customer for the cost of waiting. This situation is very similar to the problem of when to cut down a forest when it is growing over time. The optimal time to cut down the forest is when the growth rate of the forest is equal to the opportunity cost of the firm.[100] The opportunity cost of the firm is the return the firm could earn on its next best investment opportunity. As an example, the next best alternative for the firm could be investing the money in the bank. Initially the forest is growing at a rate that is faster than the bank's rate, and this means the firm can earn more money through the forest than they would at the bank. Eventually the forest growth rate decreases to a level where it equals the bank rate. Once the growth rate equals the bank's rate, the firm is incented to cut the forest down and invest the money in the bank.

In the rooftop solar adoption example, the forest growth is similar to the decreasing solar cost. Initially the solar cost declines are so large that the customer can earn more money by waiting and capturing the lower solar cost. Eventually the cost of waiting becomes larger than the benefit and at that point the customer would have an incentive to stop waiting and install solar.

The decision to wait to install solar is first demonstrated with equations. The residential customer will install solar if the net present value of installing today is greater than the net present value of delaying the installation by one year.

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[100] Varian, H. (2006). Intermedate Microeconomics.

Variables:

C = Cost of installing solar in year 1

K_2 = Cost of installing solar in year 2

q_2 = cost decline solar in year 2 = $(C – K_2)/ C = C/C – K_2/C = 1 – K_2/C$

$Profit_1$ = Savings in electricity costs earned by the residential customer in year 1

$Profit_2$ = Savings in electricity costs earned by the residential customer in year 2

$Profit_3$ = Savings in electricity costs earned by the residential customer in year 3

NPV(install in year 1) = Net present value if the customers installs solar at the start of year 1

NPV(install in year 2) = Net present value if the customer installs solar at the start of year 2

r = The real discount rate of the residential customer

Equation:

Equation 1 : NPV(install year 1) = $-C + Profit_1/(1 + r) + Profit_2/(1+r)^2 + Profit_3/(1+r)^3$

Equation 2 : NPV(install year 2) = $-K_2/(1 + r) + Profit_2/(1 + r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4$

Equation 1 is the net present value of earnings of a residential customer that installs solar in year 1. Equation 2 is the net present value of earnings of a residential customer that installs solar in tear 2. If the customer delays the investment, they will earn a return in the fourth year. This is accounted for in the '$Profit_4/(1+r)^4$' term.

If Equation 1 is greater than Equation 2 then the residential customer will find it more profitable to install solar in year 1 compared to installing solar in year 2.

Equation 3: NPV(install in year 1) > NPV(install in year 2)

Equation 3: $-C + Profit_1/(1 + r) + Profit_2/(1+r)^2 + Profit_3/(1+r)^3 > -K_2/(1 + r) + Profit_2/(1 + r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4$

By dropping $Profit_2/(1+r)^2 + Profit_3/(1+r)^3$ from each side of the equation we get:

Equation 4: $-C + Profit_1/(1 + r) > -K_2/(1 + r) + Profit_4/(1+r)^4$

Add C to each side of the equation:

Equation 5: $Profit_1/(1 + r) > C – K_2/(1 + r) + Profit_4/(1+r)^4$

Multiply by (1 + r)

Equation 6: $Profit_1 > C(1+r) – K_2 + Profit_4/(1+r)^3$

Divide by C

Equation 7: $Profit_1 / C > (1+ r) – K_2/ C + (Profit_4/(1+r)^3)/C$

Next we introduce Equation 8. Equation 8 rearranges the formula for q (the cost decline of solar).

Equation 8: $q_2 = (C – K_2)/ C = C/C – K_2/C = 1 – K_2/C$

Equation 9: $q_2 = 1 – K_2/C$

Equation 10: $K_2/C = 1 – q_2$

Equation 10 can then be plugged into Equation 7.

Equation 11: $Profit_1 / C > (1+r) – (1-q_2) + (Profit_4/(1+r)^3)/C$

Equation 12: $Profit_1 / C > r + q_2 + (Profit_4/(1+r)^3)/C$

Equation 12 is our final result. The profit in year 1 divided by the cost of installing solar in year 1 must be greater than the real discount rate plus the cost decline of solar plus the earnings in the fourth year. If this is the case then the customer does not have an incentive to wait one year to install solar and the customer will choose to install solar in year 1.

Equation 12 demonstrates the two competing forces that determine if the incentive to wait is high enough to delay a solar investment. If the customer delays the investment, they forego the earnings in the year that they delayed. This is the $Profit_1$ / C term in Equation 12. This is the cost associated with delaying the solar investment. The benefit of delaying the solar invest is that the customer is pushing out solar costs to a late year (the benefit of this is the discount rate of the customer - r) and the solar cost decline (q_2) and the customer will earn a return in the fourth year. In order for waiting to be profitable, the discount rate plus the cost decline plus the profit in the fourth year must be greater than the lost profit in the year that the customer delayed. If the discount rate, the cost decline and the earnings in the fourth year cannot cover the lost earnings in the delayed period, the customer will not choose to delay the investment.

This rule is applied to the solar adoption scenario for residential customers.

Equation 12 still holds for a 25 year time horizon because the returns from years 2 to 25 cancel each other out on each side of the equations. Due to the longer investment period in the solar example, the profit term in the fourth year becomes the profit in the 26th year.

Table 4 states the earnings that the residential customer can earn in year 1 and year 26. The 26th year is included in the analysis because if the customer delays the solar investment, they will earn a return in the 26th year. The 26th year is 2044 (25 years after 2019). The example uses

ATCO's 3rd quintile. ATCO's 3rd quintile has an incentive to install solar in 2019. The analysis determines if ATCO's 3rd quintile will find it profitable to wait and install solar in 2020 instead.

Table 4 - Earnings in t=1 for ATCO's 3rd Quintile

	Column A	Column B	Column C
Year	Annual Electricity Cost (Grid Electricity) $/year	Annual Electricity Cost (Grid Electricity Supplemented with Solar) $/year	Diference
2019	$ 1,573	$ 556	$ 1,016
2044	$ 2,817	$ 1,011	$ 1,806

The earnings from installing solar are the electricity cost savings that are achieved from installing solar. The electricity cost saving from installing solar is the difference between the cost of consuming from the grid without a solar panel minus the cost of consuming from the grid with a solar panel. In 2019, the difference is $1016 (this value can also be found in Table 2). In 2044 the difference is 1806. The return is increasing due to increasing cost of transmission and distribution.

Table 5 then states the variable that are needed to substitute into Equation 12.

Table 5 - Variables to Determine if customer will wait

Variable	Value
C	$ 17,162
K2	$ 16,589
q2	(17162-16589)/17162 = 0.033
Profit 1	$ 1,016
Profit 2	$ 1,806
r	6.62%

By plugging in the values in Table 5 into Equation 12 we get:

Equation 12: $Profit_1 / C > r + q_2 + (Profit_{26}/(1+r)^{25})/C$

$1016 / 17162 > 0.06 + 0.033 + (1806 /(1.066)^{25})/17162$

$0.059 > 0.066 + 0.033 + 0.02$

$0.059 > 0.12$

The equation is false. This means that the consumer has the incentive to wait one year. The net present value on installing solar in 2019 is less than the net present value of waiting and installing solar in 2020.

The next decision that the customer needs to make is if they will install in 2020 or wait to install in 2021.

Additional Variables:

K_3 = cost of solar in year 3

q_3 = cost decline solar in year 3 = $(K_2 – K_3)/ K_2 = K_2/K_2 – K/K_3 = 1 – K_2/K_3$

$Profit_5$ = Profit earned in the 5^{th} year.

Equations:

Equation 13: NPV(install in year 2) = $-K_2/(1 + r) + Profit_2/(1 + r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4$

Equation 14: NPV(install in year 3) = $-K_3$ / (1+r)^2 + $Profit_3$/(1+r)^3 + $Profit_4$/(1+r)^4 + $Profit_5$/(1+r)^5

Equation 15: $q_3 = (K_2 – K_3)/ K_2$

If the residential customer waits until the third year to install solar, the cost of solar will fall to K_3. Equation 14 is the net present value of installing solar in the third period. The customer pays for the cost of solar in the third period (discounted to the first year) plus the profits earned in the third year, fourth and fifth year from the solar panel installation. Equation 13 is the same logic but for a customer that installs solar in the second year.

If Equation 13 is greater than Equation 14, then the customer will have an incentive to install solar in the second period. If not, the customer will wait until the third period.

Equation 16 compares the NPV of installing in the second year to installing in the third year.

Equation 16: $-K_2$/(1 + r) + $Profit_2$/(1 + r)^2 + $Profit_3$/(1+r)^3 + $Profit_4$/(1+r)^4 > $-K_3$ / (1+r)^2 + $Profit_3$/(1+r)^3 + $Profit_4$/(1+r)^4 + $Profit_5$/(1+r)^5

By cancelling out the profit in the third and fourth period on each side of the equation you get:

Equation 17: $-K_2$/(1 + r) + $Profit_2$/(1 + r)^2 > $-K_3$ / (1+r)^2 + $Profit_5$/(1+r)^5

Multiply by (1 +r)

Equation 18: $-K_2$ + $Profit_2$ / (1+r) > $-K_3$ / (1+r) + $Profit_5$/(1+r)^4

Multiply by (1+r) and divide by K_2

Equation 19: -(1+r) + $Profit_2$ / K_2 > $-K_3$ / K_2 + $Profit_5$/(1+r)^3/K_2

Next we introduce Equation 19. Equation 19 rearranges the formula for q_3 (the cost decline of solar).

Equation 20: $q_3 = (K_2 – K_3)/ K_2 = K_2/K_2 – K_3/K_2 = 1 – K_3/K_2$

Equation 21: $q_3 = 1 – K_3/K_2$

Equation 22: $K_3/K_2 = 1 – q_3$

Equation 22 can then be plugged into Equation 19.

Equation 23: $-(1+r) + Profit_2 / K_2 > - (1- q_3) + Profit_5/(1+r)^3/K_2$

Equation 24: $Profit_2/K_2 > (1+r) – (1-q_3) + Profit_5/(1+r)^3/K_2$

Equation 25: $Profit_2 / K_2 > r + q_3 + Profit_5/(1+r)^3/K_2$

The result in equation 25 is the same as the result from Equation 12, but shifted one period forward. $Profit_1/C$ in equation 12 becomes $Profit_2 / K_2$ in equation 25. The term q_2 in equation 12 becomes q_3 in equation 25. $Profit_4$ in Equation 12 becomes $Profit_5$ in equation 25. The C term in Equation 12 become K_2 in equation 25.

The exponent on the (1+r) term in Equation 12 is the same as the exponent in the (1+r) term in Equation 25. This is because the exponent is the length of the investment period (3 years). The length of the investment period does not change when delays of the investment occur. A 3 year investment made one year later is still a 3 year investment. This pattern can be applied to the decision to wait in the third, fourth, and all proceeding years. Equation 26 is the general equation.

Equation 26: $Profit_x / K_x > r + q_{x+1} + Profit_{x+25}/(1+r)^25/K_x$

$Profit_x$ = Profit earned in year x if the customer does not delay the investment

K_x = Cost of investing if the customer does not delay

q_{x+1} = Cost declines from year x to year x+1

$Profit_{x+25}$ = Profit earned in year x+25 as a result of delaying investment

The subscript 'x' is the year that the profits or the cost of solar occurs. Note that the subscript 'x' does include information on if the payment or cost occurs at the beginning or the end of the period. Profits occurs at the end of the year and solar costs occur at the start.

Table 6 shows the Profit/K compared to q+r for the years 2019 to 2033. Column B is the cost of solar in the given year and Column C is the cost of solar in the year after. These values can be found in Table 3. Column D the percentage change in the solar cost. The solar forecast has cost declines of 3.3% annually from 2017 to 2030. After 2030 the solar cost is forecast to stay flat. Kost et el. does not provide a solar forecast past 2030. The flat solar cost after 2030 assumes that in 2030 the cost of solar will not be able to decline any further due to technological constraints. Column E is the real interest rate (6.6%) plus q. Column F and G are the annual costs of using the grid with and without a solar panel (these values can also be found in Table 2). Column H is the profit in the current year. It is the difference between the cost of consuming electricity from the grid without a solar panel and the cost of consuming electricity with a solar panel. Column I is the annual profit divided by the initial investment in Column B.

Table 6 - Incentive to wait for ATCO's 3rd Quintile – Part 1

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I
Year(x)	Solar cost in year x: K(x)	Solar cost in following year: K(x + 1)	q	q+r	Annual Electricity Cost (Grid Electricity) $/year	Annual Electricity Cost (Grid Electricity Supplemented with Solar) $/year	Profit in year x: Profit(x)	Profit(x)/K(x)
2019	$ 17,162	$ 16,589	3.3%	10.0%	$ 1,573	$ 556	$ 1,016	5.9%
2020	$ 16,589	$ 16,034	3.3%	10.0%	$ 1,681	$ 571	$ 1,109	6.7%
2021	$ 16,034	$ 15,499	3.3%	10.0%	$ 1,747	$ 582	$ 1,165	7.3%
2022	$ 15,499	$ 14,981	3.3%	10.0%	$ 1,935	$ 598	$ 1,337	8.6%
2023	$ 14,981	$ 14,480	3.3%	10.0%	$ 1,997	$ 613	$ 1,384	9.24%
2024	$ 14,480	$ 13,997	3.3%	10.0%	$ 2,028	$ 628	$ 1,400	9.7%
2025	$ 13,997	$ 13,529	3.3%	10.0%	$ 2,018	$ 639	$ 1,378	9.8%
2026	$ 13,529	$ 13,077	3.3%	10.0%	$ 2,105	$ 655	$ 1,450	10.7%
2027	$ 13,077	$ 12,640	3.3%	10.0%	$ 2,134	$ 671	$ 1,464	11.2%
2028	$ 12,640	$ 12,218	3.3%	10.0%	$ 2,164	$ 686	$ 1,478	11.7%
2029	$ 12,218	$ 11,810	3.3%	10.0%	$ 2,195	$ 702	$ 1,493	12.2%
2030	$ 11,810	$ 11,810	0.0%	6.6%	$ 2,225	$ 718	$ 1,507	12.8%

Table 7 shows the calculation of the additional earning made in if the solar investment is delayed. This is the ‘$Profit_{x+25}/(1+r)^{25}/K_x$’ term in Equation 26. ‘x’ is used to denote the year that the profit or the cost is incurred. ‘x’ does not provide information on if the profit or the cost occurred at the beginning or the end of the year. Profit occurs at the end of the year and costs occur at the start.

Column B in Table 7 show the cost of solar in the years 2019 to 2030. This is the same as Column B in Table 6 (the year 2044 is 25 years after 2019). Column C and D show the annual electricity costs associated with using the grid without and with a solar panel in 2044 to 2055. Column E is the profit or the electricity cost savings that can be accrued if a solar panel is installed for each year. The profit is discounted back 25 periods, to bring it back to year x (as per Equation 26).

Table 7 - Incentive to wait for ATCO's 3rd Quintile – Part 2

Column A	Column B	Column C	Column D	Column E	Column F
Year (x+25)	K(x)	Annual Electricity Cost (Grid Electricity) $/year	Annual Electricity Cost (Grid Electricity Supplemented with Solar) $/year	Profit(x+25)	Profit(x+25) / (1+r)^(25) / K(x)
2044	$ 17,162	2817	1011	1806	2.1%
2045	$ 16,589	2871	1037	1834	2.2%
2046	$ 16,034	2926	1064	1862	2.3%
2047	$ 15,499	2983	1091	1892	2.5%
2048	$ 14,981	3041	1119	1922	2.6%
2049	$ 14,480	3102	1148	1953	2.7%
2050	$ 13,997	3164	1178	1985	2.9%
2051	$ 13,529	3228	1209	2019	3.0%
2052	$ 13,077	3294	1241	2053	3.2%
2053	$ 12,640	3361	1273	2088	3.3%
2054	$ 12,218	3431	1307	2124	3.5%
2055	$ 11,810	3503	1342	2161	3.7%

Table 8 compares Column I in table 6 to Column E in Table 6 and Column F in Table 7. These terms are the three groups of terms found in Equation 26.

If Column A in Table 8 is less than Column D in Table 8 then the customer will have an incentive to wait. In this case the incentive to wait stops in 2030 when Column A (13%) becomes less than Column D (10%). This is caused by the cost of solar declines stopping in 2030. At this point the cost of waiting is greater than the benefit and the customer will choose to install.

	Column A	Column B	Column C	Column D
Year(x)	Profit(x)/K(x)	q+r	Profit(x+25) / (1+r)^(25) / K(x)	Column B plus Column C
2019	6%	10%	2.1%	12%
2020	7%	10%	2.2%	12%
2021	7%	10%	2.3%	12%
2022	9%	10%	2.5%	12%
2023	9%	10%	2.6%	13%
2024	10%	10%	2.7%	13%
2025	10%	10%	2.9%	13%
2026	11%	10%	3.0%	13%
2027	11%	10%	3.2%	13%
2028	12%	10%	3.3%	13%
2029	12%	10%	3.5%	13%
2030	13%	7%	3.7%	10%

As a result of the incentive to wait and accrue the benefit of lower solar costs, ATCO's 3rd quintile delays their installation by 11 years. The initial installation date in 2019 is pushed out to 2030.

There are two major reasons why the incentive to install solar are delayed. The first is that the cost of solar is declining each year, so there are benefits to waiting and achieving a lower solar cost. The second reason why delaying solar is profitable is that the cost of staying on the grid is increasing each year. The increasing price of staying on the grid means that the annual earnings from a solar panel increases each year that passes. The residential customer can forego earnings in the early years of the installation and still collect the higher returns later on when the electricity and transmission prices have increased. This effect further increases the incentive to wait and cash in on the lower solar costs at a later date.

A sensitivity analysis is done in Chapter 6 to test how the incentive to wait would be impacted by flat transmission and distribution prices past 2030. If transmission and distribution prices do not grow over time past 2030, on a real basis, the incentive to wait is smaller. This sensitivity is important to understanding how transmission and distribution price growth impacts the incentive to wait for residential solar customers.

Chapter 6 Timing of Rooftop Solar Adoption

ATCO Electric customers will be the first to substitute to solar in Alberta, because of their high variable charge for transmission and distribution. Customers that consume the most electricity will be the first to install solar generation because they have the highest economic incentives to install solar under the microgeneration legislation.

Table 8 - ATCO Consumption Distribution[101]

Quintile	Average Monthly Consumption (kWh)	Capacity Required for Annual Net Zero Electricity Consumption (kW)	Percentage of Service Area Consumption
1	244	Unable to install solar	8%
2	392	Unable to install solar	13%
3	508	5	17%
4	646	7	22%
5	1142	12	39%

[101] The average monthly consumption uses the average consumption listed by the MSA and adjusts it by the distribution provided by Enmax.

Market Surveillance Administrator (2016). "2016-06-30 MSA Retail Market Statistics." Retrieved November 29th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-06-30_MSA_retail_market_statistics.xlsx.

The capacity listed is the capacity required to create net zero electricity consumption from the grid over the course of one year, assuming a 13.5 % capacity factor. This set-up results in households over producing in the summer and under producing in the winter. The solar resource is much stronger in the summer months compared to the winter months. This is especially the case for ATCO customers in the north where seasonality of sunlight is much more extreme. Residential customers need to install large enough systems such that the excess production in the summer months can offset their consumption in the winter months when the sun is more scarce. The annual capacity factor for Grand Prairie is used as the annual average solar energy that can be produced by solar panels for all customers in ATCO's service area. Grand Prairie sits within ATCO's service area.

Table 8 states that the 1st and 2nd quintiles of ATCO's service area cannot install solar. These customers are left out because they are likely to live in attached housing units and as a result are unlikely to install solar (see chapter 4 for discussion of a residential customer's ability to install solar in an attached housing situation). In 2016, 36 percent of households in Alberta lived in some form of detached housing (condo, apartments, other).[102] The first two quintiles represent 40% of residential customers and are likely residents living in attached housing.

Residential customers will install large systems because this reduces the cost of solar systems. The largest possible system on a household creates the lowest solar cost, on a per kW basis.

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[102] Statistics Canada (2016). "2016 Census." Retrieved April 23rd, 2018, from https://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/famil55c-eng.htm.

Customers can achieve a better return with larger systems. The constraint is that households cannot install systems that produce more electricity than they consume over the course of a year. This means that customers will install systems large enough to create net zero electricity consumption from the grid. This assumption is applied to all residential customers in the province.

As shown by the table, high consumers can install large systems (12 kW for the 5th quintile). This is followed by the 4th quintile, with 7 kW systems, until the 3rd quintile substitutes with 5 kW systems. The above distribution is the Enmax distribution adjusted to match the ATCO service area. Enmax's distribution is adjusted by scaling the distribution such that the average customer in the distribution matches the average ATCO customer. This assumes that the shape of the ATCO customer distribution is the same as the Enmax distribution. This process of adjusting the Enmax distribution is also done for Fortis and Epcor.

It is possible that Fortis and ATCO have very different distributions of electricity use compared to Enmax. Enmax is an urban area and ATCO and Fortis cover Alberta's rural areas. If the distribution of electricity use is different for Fortis and ATCO it means that the size of solar systems is misstated in this analysis. This would have a large impact on the date of substitution and a small impact on the total MW installed.

The number of residential sites in each service area is used to determine the MW of solar capacity installed in each year. The number of residential sites in each service area is listed in the

MSA's retail statistics.[103] The number of sites is increased by the percentage increase of a population forecast done by the Alberta government. The assumption is that the number of residential sites will grow at the same rate as Alberta's population.[104]

The first scenario shows the solar adoption for the four distribution areas, using Kost's rate of solar cost declines. This is referred to as the base case scenario.

ATCO's 5th quintile substitute first, in 2026. This results in 402 MW of residential rooftop solar being installed. This is a result of twenty percent (one quintile) of the sites in ATCO service territory substituting to solar and installing 11.56 kW systems. There are 174,170 residential sites in the entire ATCO service area in 2022, and 34,834 sites in each quintile. Multiplying 34,834 sites by 11.56 kW system results in 402 MW of rooftop solar additions in the fifth quintile.

The capacity of rooftop solar installed grows each year after substitution occurs due to population growth in ATCO's service area. In 2029 the 4th quintile in ATCO's service area substitutes to solar. This results in 237 MW of solar being installed. In 2030 an additional 189 MW of solar is installed from the 3rd quintile substituting to solar.

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[103] Market Surveillance Administrator. "Retail Statistics." Retrieved August 28th, 2017, from http://albertamsa.ca/uploads/pdf/Archive/00000-2017/RetailStatistics.xlsx.

[104] Office of Statistics and Information - Demography (2017). "Population Projection Highlights." Retrieved August 28th, 2017, from http://finance.alberta.ca/aboutalberta/osi/demographics/Population-Projections/2017-2041-Alberta-Population-Projections-Highlights.pdf.

The incentive to wait has outline in section 5.2.10 has a big impact on the substitution date of ATCO customers. If ATCO customers do not consider the cost savings from delaying investment they would substitute nine to thirteen years earlier, depending on the quintile. The incentive to wait has the biggest impact on ATCO customers compared to other DFO service area. ATCO is highly impact by the incentive to wait because ATCO's high transmission and distribution charges create larger and larger returns as transmission and destruction charges increase over the forecast. The other DFO service areas have lower transmission and distribution charges and as a result the increases are also smaller, on a dollar basis. The smaller increase on a dollar basis creates a lower incentive to wait in other DFO service areas.

All forecast values stated in the paper include the incentive to wait in the customer's decision making process. Including the incentive to wait is important to accurately explain the behavior of residential customers.

Table 9 - Fortis Consumption Distribution[105]

Quintile	Average Monthly Consumption (kWh)	Capacity Required for Annual Net Zero Electricity Consumption (kW)	Percentage of Service Area Consumption
1	271	Unable to install solar	8%
2	436	Unable to install solar	13%
3	564	5	17%
4	717	6	22%
5	1269	11	39%

The 5th quintile substitutes in 2028 and this results in 1311 MW of rooftop solar installations. The same assumptions of population growth and solar costs that were used for ATCO are used for Fortis customers. An additional 762 MW is installed in 2030 from the 4th quintile substituting. An additional 599 MW is installed in 2030 from the 3rd quintile substituting.

[105] The average monthly consumption uses the average consumption listed by the MSA and adjusts it by the distribution provided by Enmax.

Market Surveillance Administrator (2016). "2016-06-30 MSA Retail Market Statistics." Retrieved November 29th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-06-30_MSA_retail_market_statistics.xlsx.

The incentive to wait delays Fortis' substitution dates by six to eight years, depending on the quintile. The incentive to wait is highly impactful and important part of a customer's decision making process when deciding whether to install rooftop solar panels. All forecast values stated in the paper include the incentive to wait in the customer's decision making process. See Table 10 to 12 for Fortis's 3rd Quintile's incentive to wait impacts the installation date.

Table 10 - Fortis' 3rd Quintile Incentive to Wait - Part 1

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I
Year(x)	Solar Cost in year x: K(x)	Solar Cost in following year: K(x+1)	q	q+r	Annual Electricity Cost (Grid Electricity) $/year	Annual Electricity Cost (Grid Electricity Supplemented with Solar) $/year	Profit in year x: Profit(x)	Profit(x)/K(x)
2017	$18,190	$17,583	3.3%	10.0%	1069	386	683	4%
2018	$17,583	$16,995	3.3%	10.0%	1195	394	800	5%
2019	$16,995	$16,427	3.3%	10.0%	1212	404	808	5%
2020	$16,427	$15,879	3.3%	10.0%	1315	415	900	5%
2021	$15,879	$15,348	3.3%	10.0%	1375	423	952	6%
2022	$15,348	$14,835	3.3%	10.0%	1566	434	1132	7%
2023	$14,835	$14,340	3.3%	10.0%	1618	445	1173	8%
2024	$14,340	$13,861	3.3%	10.0%	1634	456	1179	8.2%
2025	$13,861	$13,398	3.3%	10.0%	1609	464	1145	8.3%
2026	$13,398	$12,950	3.3%	10.0%	1687	475	1212	9.0%
2027	$12,950	$12,517	3.3%	10.0%	1701	486	1215	9%
2028	$12,517	$12,099	3.3%	10.0%	1716	497	1218	9.7%
2029	$12,099	$11,695	3.3%	10.0%	1730	509	1222	10.1%
2030	$11,695	$11,695	0.0%	6.6%	1745	520	1225	10.5%

Table 10 provides the first step in determining Forts' 3rd quintile's incentive to wait. Columns E and I are used by Fortis customers to determine the cost and benefit of waiting to install solar. Column E is the benefit of installing solar one period later. Fortis customers benefit by delaying by receiving a lower solar cost (represented by q) and Fortis customers benefit by incurring solar costs one year later (represented by the discount rate r). The cost of installing solar one year later is the profits that could have been earned in the year that they delay occurred. This value is stated in Column I.

Table 11 provides the last term in Equation 26 required to determine if waiting to install is less than the cost. Column F in Table 11 is the profit that the Fortis customer receives in the last year of the delayed solar investment. Year 'x' is the year that the customer initially has an incentive to install solar. If the customer delays, they can earn a return 25 years later (x+25) as a result of the delayed solar investment.

Table 11 - Fortis' 3rd Quintile Incentive to Wait - Part 2

Column A	Column B	Column C	Column D	Column E	Column F
Year (x+25)	K(x)	Annual Electricity Cost (Grid Electricity) $/year	Annual Electricity Cost (Grid Electricity Supplemented with Solar) $/year	Profit(x+25)	Profit(x+25) / (1+r)^(25) / K(x)
2042	$18,190	$ 1,994	$ 695	1299	1.4%
2043	$17,583	$ 2,020	$ 712	1308	1.5%
2044	$16,995	$ 2,048	$ 730	1317	1.6%
2045	$16,427	$ 2,076	$ 749	1327	1.6%
2046	$15,879	$ 2,105	$ 768	1337	1.7%
2047	$15,348	$ 2,135	$ 788	1347	1.8%
2048	$14,835	$ 2,166	$ 808	1358	1.8%
2049	$14,340	$ 2,197	$ 829	1368	1.9%
2050	$13,861	$ 2,230	$ 850	1380	2.0%
2051	$13,398	$ 2,263	$ 872	1391	2.1%
2052	$12,950	$ 2,298	$ 895	1403	2.2%
2053	$12,517	$ 2,333	$ 918	1415	2.3%
2054	$12,099	$ 2,369	$ 942	1427	2.4%
2055	$11,695	$ 2,407	$ 967	1440	2.5%

Column E and I in Table 10 and Column F in Table 11 are then compared in Table 12. If the foregone profit in year 1 is less than the cost decline (q), discount rate (r) and the discounted profit in year x + 25, then the customer will choose to delay the investment. If the cost of delaying (foregone profit in year x) is less the benefit, the customer can earn more money by delaying the investment.

Table 12 - Fortis' 3rd Quintile Incentive to Wait - Part 3

	Column A	Column B	Column C	Column D
Year(x)	Profit(x)/ K(x)	q+r	Profit(x+25) / (1+r)^(25) / K(x)	Column B plus Column C
2017	3.8%	10.0%	1.4%	11.4%
2018	4.6%	10.0%	1.5%	11.5%
2019	4.8%	10.0%	1.6%	11.5%
2020	5.5%	10.0%	1.6%	11.6%
2021	6.0%	10.0%	1.7%	11.7%
2022	7.4%	10.0%	1.8%	11.7%
2023	7.9%	10.0%	1.8%	11.8%
2024	8.2%	10.0%	1.9%	11.9%
2025	8.3%	10.0%	2.0%	12.0%
2026	9.0%	10.0%	2.1%	12.1%
2027	9.4%	10.0%	2.2%	12.1%
2028	9.7%	10.0%	2.3%	12.2%
2029	10.1%	10.0%	2.4%	12.3%
2030	10.5%	6.6%	2.5%	9.1%

The year that the cost of delaying investment (Column A in Table 12) is greater than the benefit (Column D in Table 12), the solar customer will install solar. This occurs in 2030.

Table 13 - EPCOR Consumption Distribution[106]

[106] The average monthly consumption uses the average consumption listed by the MSA and adjusts it by the distribution provided by Enmax.

Ibid.

Quintile	Average Monthly Consumption (kWh)	Capacity Required for Annual Net Zero Electricity Consumption (kW)	Percentage of Service Area Consumption
1	205	Unable to install solar	8%
2	330	Unable to install solar	13%
3	428	4	17%
4	544	5	22%
5	962	9	39%

Epcor customers consume the least electricity of all of the four distribution service areas. This results in the smallest rooftop solar systems being installed in Epcor's service area for all five quintiles.

Epcor's 5th quintile substitutes to solar in 2030. This results in 800 MW of solar being installed by residential customers in Epcor's area. None of the other quintile's in EPCOR's service area experience an incentive to substitute to solar by 2030. The later substitution date is driven by Epcor's low distribution and transmission charges (2nd lowest of the four distribution companies) and Epcor's low consumption (smaller systems result in higher solar costs per kW).

EPCOR's 5th, 4th and 3rd quintiles are impacted by the incentive to wait. The substitution date is pushed out three to eight years as a result of the incentive to capture lower solar costs. The reason that EPCOR's 5th quintile has such a high incentive to wait is that the lost annual electricity cost savings do not reach a level such that they outweigh the benefit of the solar cost declines and discount rate (see Table 14 below).

Table 14 shows the terms in Equation 26 that are used to determine if EPCOR's 5th Quintile of customers have an incentive to wait to install solar. The steps to calculate the Columns in Table 14 are not included in this explanation. The process for EPCOR customers is the same as the process described for Fortis and ATCO customers.

EPCOR's 5th Quintile will substitute when the cost of waiting (Column A in Table 14) is greater than the benefit (Column D in Table 14). This occurs in 2030. It is more profitable to install than to delay the installation to the next year.

Table 14 - EPCOR's 5th Quintile Incentive to Delay Investment

	Column A	Column B	Column C	Column D
Year(x)	Profit(x)/K(x)	q+r	Profit(x+25) / (1+r)^(25) / K(x)	Column B plus Column C
2017	4%	10.0%	1.4%	11.4%
2018	5%	10.0%	1.5%	11.4%
2019	5%	10.0%	1.5%	11.5%
2020	6%	10.0%	1.6%	11.6%
2021	6%	10.0%	1.7%	11.6%
2022	8%	10.0%	1.7%	11.7%
2023	8%	10.0%	1.8%	11.7%
2024	8%	10.0%	1.9%	11.8%
2025	8%	10.0%	1.9%	11.9%
2026	9%	10.0%	2.0%	12.0%
2027	10%	10.0%	2.1%	12.0%
2028	10%	10.0%	2.2%	12.1%
2029	10%	10.0%	2.3%	12.2%
2030	11%	6.6%	2.3%	9.0%

Table 15 - ENMAX Consumption Distribution[107]

Quintile	Average Monthly Consumption (kWh)	Capacity Required for Annual Net Zero Electricity Consumption (kW)	Percentage of Service Area Consumption
1	223	Unable to install solar	8%
2	358	Unable to install solar	13%
3	464	4	17%
4	590	5	22%
5	1043	10	39%

Enmax customers consume approximately the same amount of electricity as ATCO customers. The difference between Enmax and ATCO is that ATCO has the highest distribution and transmission charges and Enmax has the lowest. Also Enmax has a better capacity factor compared to ATCO. Enmax's 5th quintile is forecast to substitute to solar in 2030. This results in 1060 MW of solar installations in 2030. None of Enmax's other quintiles have sufficient incentive to install solar by 2030.

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[107] The average monthly consumption uses the average consumption listed by the MSA and adjusts it by the distribution provided by Enmax.

Ibid.

Enmax's 5th quintile's incentive to wait is shown in Table 16. Enmax has an incentive to wait until Column D (profits from installing solar) reaches a high enough level that they equal or are greater than the benefit of delaying (Column A). This does not happen before 2030. The customer expects the cost of staying on the grid to continue to increase, and for this reason they have an incentive to wait until Column A becomes higher than Column D. This occurs in 2030.

Table 16 - Enmax's 5th Quintile's incentive to Wait

	Column A	Column B	Column C	Column D
Year(x)	Profit(x)/K(x)	q+r	Profit(x+25) / (1+r)^(25) / K(x)	Column B plus Column C
2017	3%	10.0%	1.4%	11.4%
2018	4%	10.0%	1.5%	11.5%
2019	5%	10.0%	1.6%	11.5%
2020	5%	10.0%	1.6%	11.6%
2021	6%	10.0%	1.7%	11.6%
2022	8%	10.0%	1.8%	11.7%
2023	8%	10.0%	1.8%	11.8%
2024	8%	10.0%	1.9%	11.9%
2025	8%	10.0%	2.0%	11.9%
2026	9%	10.0%	2.1%	12.0%
2027	10%	10.0%	2.1%	12.1%
2028	10%	10.0%	2.2%	12.2%
2029	10%	10.0%	2.3%	12.3%
2030	11%	6.6%	2.4%	9.0%

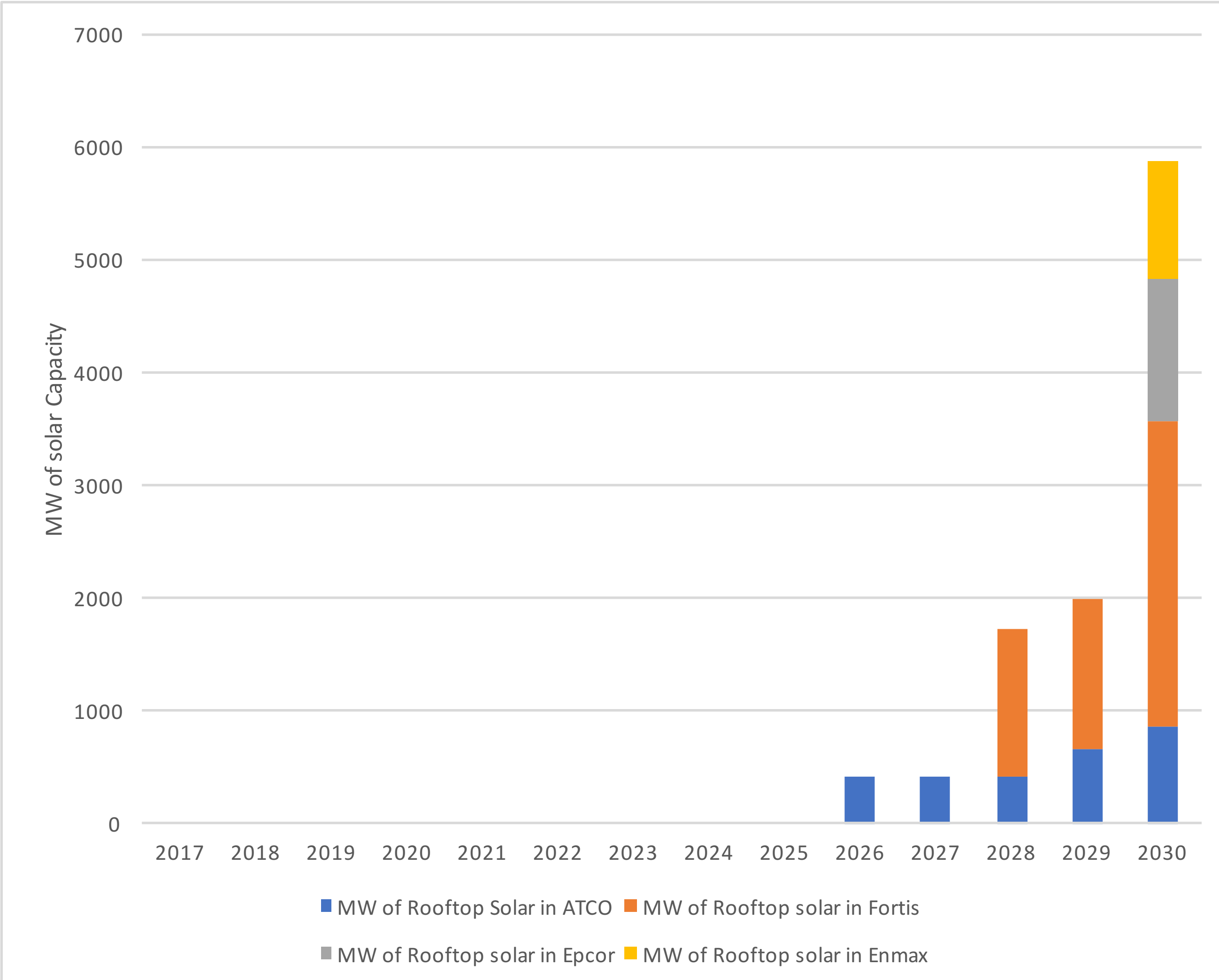
The incentive to wait is summarized for all the different DFO service areas and quintiles in Table 17.

Table 17 - Immediate Installation Date Versus Delayed Installation Date

		Quintile		
	Immediate/ Delayed Adoption year	5th	4th	3rd
Serice Area	ATCO	2017/2026	2017/2029	2018/2030
	Fortis	2017/2028	2020/2030	2022/2030
	Enmax	2022/2030	2028/DNS	DNS/DNS
	Epcor	2022/2030	2027/2030	2030/DNS
	DNS stands for 'Does Not Substitute'			

All four DFO service areas are highly impacted by the incentive to wait. For some of Fortis, Enmax and Epcor's quintiles, the flattening out of solar cost declines in 2030 incents solar installation in 2030. This is because the customer sees that the benefit of installing solar in 2031 decreases due to the flat solar cost and as a result they choose to install in 2030.

Figure 6 - Alberta Residential Rooftop Solar Adoption



ATCO, Fortis, Epcor, and Enmax added together results in 5878 MW of rooftop solar being installed by 2030. This is 44 percent of forecast peak demand in 2030, forecasted by the AESO in their 2017 Long Term Outlook.[108]

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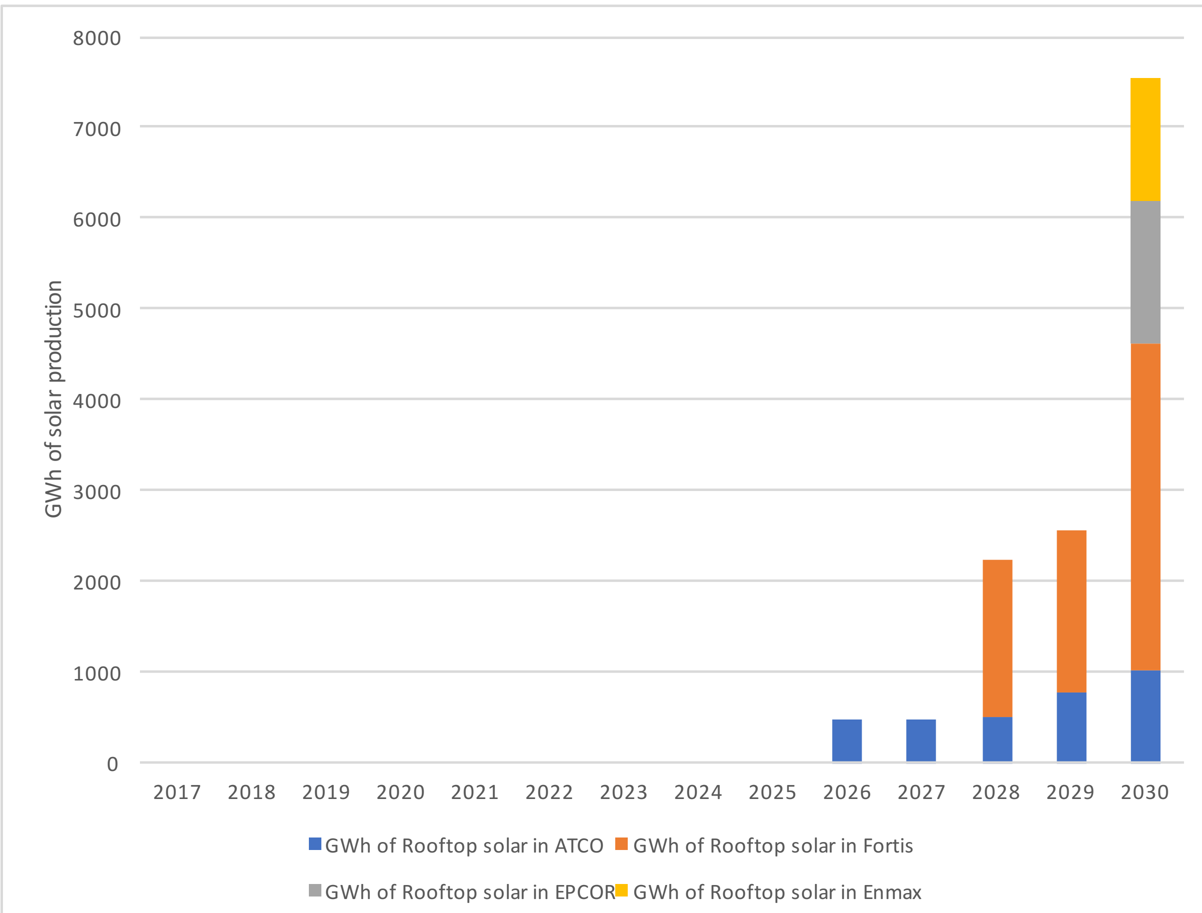
[108] 5878 MW / 13231 MW = 0.44
Alberta Electric System Operator (2017). "2017 Long Term Outlook Data File." Retrieved August 28th, 2017, from https://www.aeso.ca/download/listedfiles/2017-LTO-data-file.xlsx.

On an energy basis ATCO, Fortis, EPCOR and Enmax added together results in 7548 GWh of solar production in 2030. This is 8 percent of annual energy demand forecast by the AESO in their 2017 Long-term Outlook.[109]

Figure 7 - Alberta Rooftop Solar Adoption by Energy (GWh)



[109] 7548 GWh / 94304 GWh = 0.08
Ibid.

The reason that the MW installed capacity results in such a high percentage of peak MW consumed is the low capacity factor of solar. Capacity factor refers to the percentage of the time that a generator produces electricity at its maximum output. Solar generation is limited to the hours of the day that the solar panel receives sunlight. The assumed capacity factor of rooftop solar in Alberta is between 13.5% and 15%.[110] This means that the solar panel only produces its electricity in 13.5-15% of hours. The other 85-86.5% of the time it is either nighttime and the sun is not providing any solar energy or there is cloud cover covering the sun's rays.

The low capacity factor means that it requires a very large amount of solar capacity to cover a residential customer's total energy over the course of one year.

An implication of rooftop solar customers installing a large amount of rooftop solar in Alberta is that it would have an impact on the cost of financing. The solar adoptions would require residential customers to either invest their own money or borrow money to purchase the solar panels. These actions would impact the cost of debt in Alberta. If enough customers install solar it could increase the cost of borrowing in the market. The paper assumes perfect capital markets. The increase in demand for solar financing would be met by sufficient supply such that the cost of financing would not change.

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[110] See section 5.2.4 for discussion of capacity factor. Capacity factor is sourced from Natural Resources Canada (2017). "Photovoltaic and solar resource maps." Retrieved June 12th, 2017, from https://www.nrcan.gc.ca/18366?lang=e&m=r.

The current solar adoption in Alberta shows that the forecast represents a realistic scenario. The level of solar microgeneration installed in Alberta in February 2018 was 24 MW.[111] This is similar to the zero MW that is forecast to be installed in 2017 in the forecast.

An important takeaway from this model is that residential customers substitute in the same order as the level of their variable charges for distribution and transmission. Those with the highest distribution and transmission energy charges substitute first (ATCO). This is followed by Fortis in 2028, Epcor and Enmax in 2030. This demonstrates the impact that transmission and distribution tariffs have on rooftop solar adoption for residential customers. There is a four year difference between ATCO and Enmax substitution dates. This is largely driven by ATCO distribution and transmission rates that are 1200% higher than the Enmax rates.[112]

Another factor that impacts substitution rates is the cost of the solar panels. As described earlier, the size of a solar system has a big impact on the cost per kW installed. Different service areas will have different sized panels based on the amount of electricity they consume. Enmax and ATCO customers consume a similar amount of electricity on a monthly basis and therefore

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[111] Alberta Electric System Operator (2018). "Microgeneration Report." Retrieved March 30th, 2018, from https://www.aeso.ca/market/market-and-system-reporting/micro-generation-reporting/.

[112] The variable charge for distribution and transmission for Enmax is 0.9 cents per kWh in 2017. The variable charge for distribution and transmission for ATCO is 11 cents per kWh. 11/0.9 = 12.2 = 1220%. See Table 1 in Chapter 5 for sources.

would install similar sized systems. The size of ATCO and Enmax systems are listed in **T**ables 8 and 15 in Chapter 6.

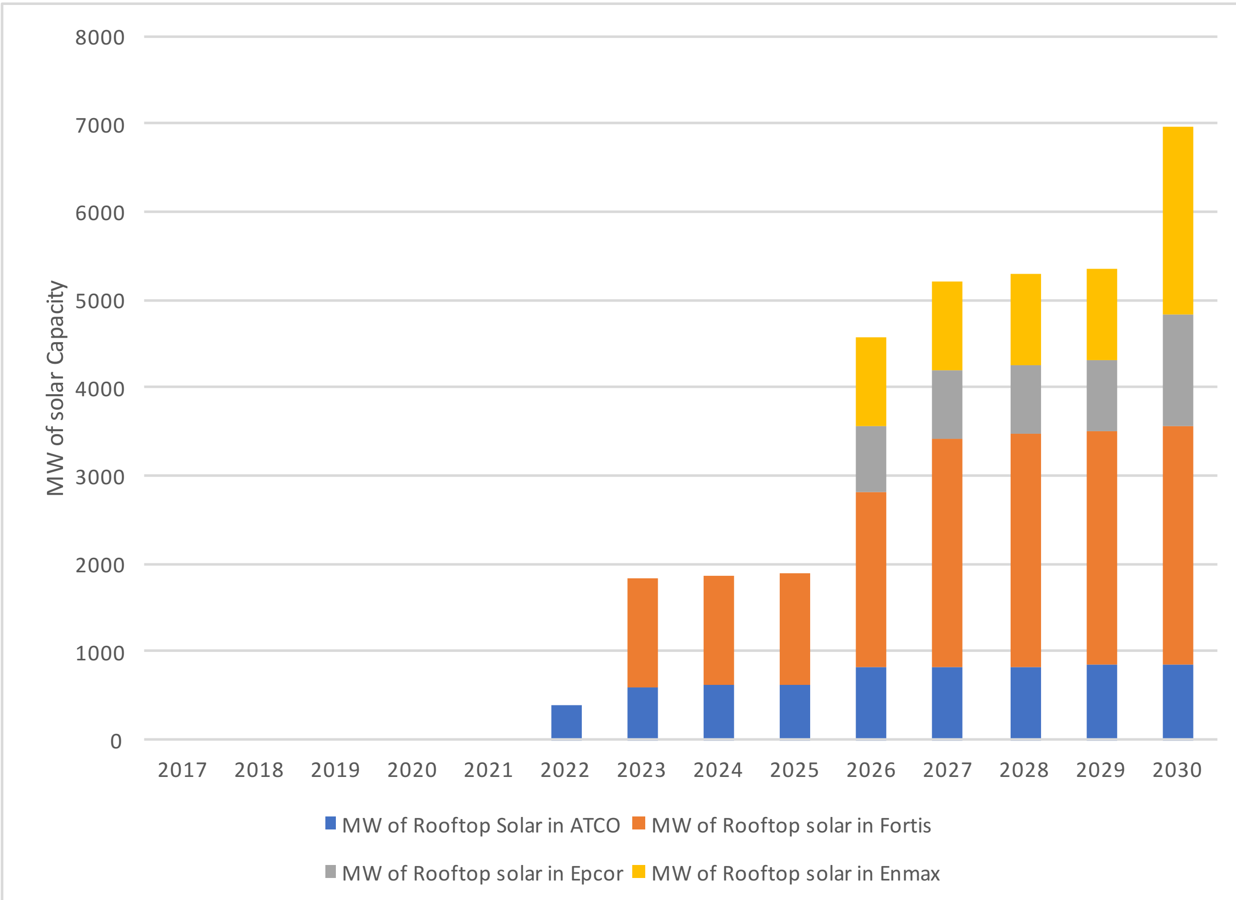
If solar costs decreased at the rate forecasted by Sunshot, solar adoptions would occur more quickly for all service areas. The following graph shows the substitution dates and MW installed of rooftop solar in Alberta if solar costs decrease at the rate forecasted by Sunshot. The low solar costs incent 6949 MW of rooftop solar installations in 2030. 6949 MW of rooftop solar is 53% of Alberta's forecasted peak demand in 2030.[113]

On an energy basis, 6949 MW of capacity would produce 8930 GWh per year of electricity. This is 9 percent of total energy consumption in Alberta in 2030, forecast by the AESO in their 2017 long term outlook.[114]

Figure 8 - Alberta Residential Rooftop Solar Adoption with Low Solar Cost

[113] 6949 MW / 13231 MW = 0.53. Alberta Electric System Operator (2017). "2017 Long Term Outlook Data File." Retrieved August 28th, 2017, from https://www.aeso.ca/download/listedfiles/2017-LTO-data-file.xlsx.

[114] 8930 GWh / 94304 GWh = 0.9. Electricity consumption for Alberta in 2030 is sourced from ibid.



The reduced cost of solar incents all service areas to substitute to solar more quickly. The population in Epcor's and Enmax's areas create larger additions in solar capacity in those areas compared to ATCO. ATCO only represents ten percent of the residential electricity sites (households) in the province (see Figure 10 in Chapter 6).

The incentive to wait has an impact on all DFO service areas in the Sunshot cost decline scenario. Table 18 compares the installation year if the customer installs solar as soon as they can earn a positive cash flow on the investment and compares it to the year the customer will install if they consider the incentive to wait.

Table 18 - Immediate Installation Year Versus Delayed Installation Year (Sunshot Cost Decline)

		Quintile		
	Immediate/Delayed Adoption year	5th	4th	3rd
Serice Area	ATCO	2017/2022	2017/2023	2018/2026
	Fortis	2017/2023	2018/2026	2019/2027
	Enmax	2019/2026	2020/2030	2021/2030
	Epcor	2019/2026	2020/2030	2020/DNS
	DNS stands for 'Does not Substitute'			

Reducing the nominal discount rate also has an impact on rooftop solar adoptions. The following calculation uses Kost's forecast of solar cost declines and a 4.8% nominal discount rate estimated by Kuby Renewables. Decreasing the nominal discount factor to 4.8% incents 0 MW from 2017 to 2029 and 6834 MW in 2030.

The reason that the solar installations get pushed out to 2030 in the 4.8% scenario is that the lower discount rate increases the incentive to wait for residential customers. This is shown in Table 19 for ATCO's 5th Quintile.

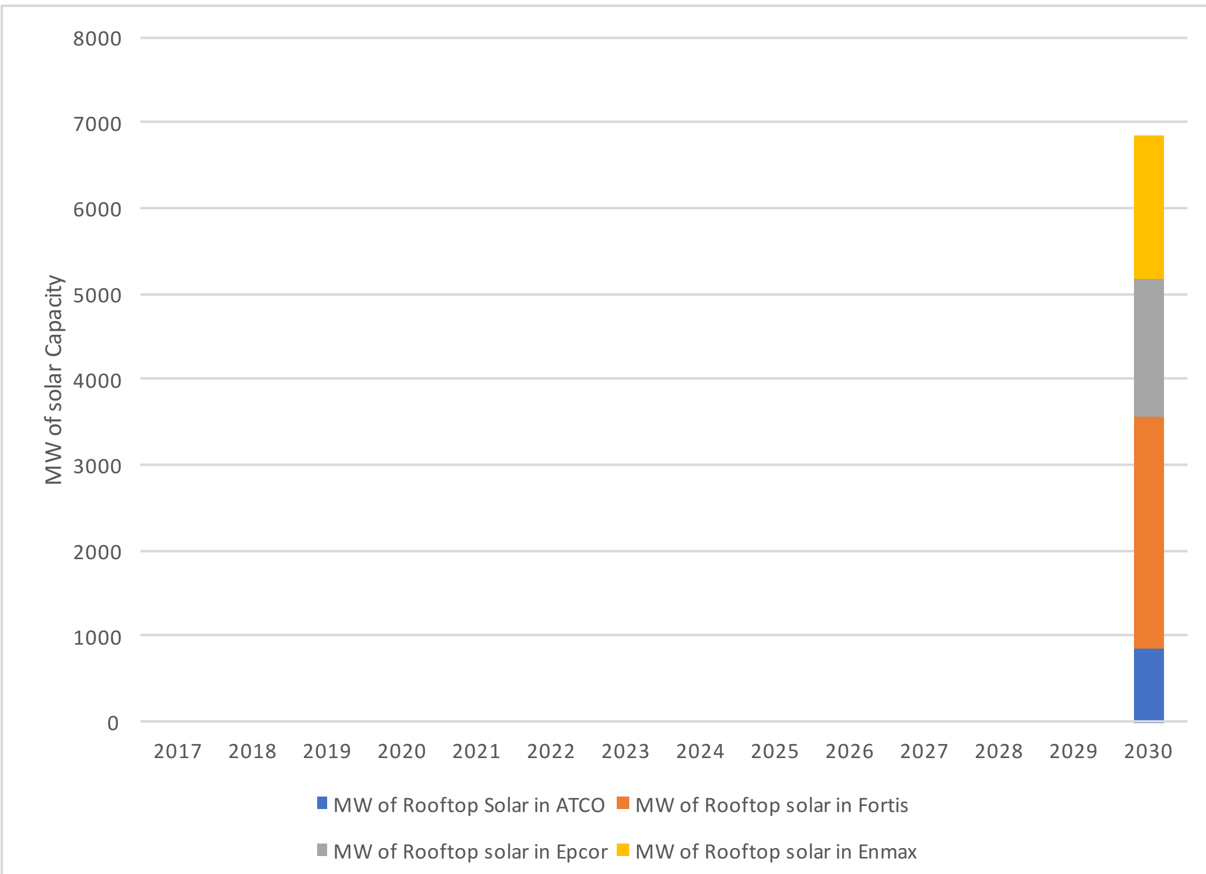
Table 19 - ATCO's 5th Quintile Incentive to Wait (4.8 Discount Rate)

	Column A	Column B	Column C	Column D
Year(x)	Profit(x)/K(x)	q+r	Profit(x+25) / (1+r)^(25) / K(x)	Column B plus Column C
2017	7%	6.1%	6.9%	13%
2018	8%	6.1%	7.2%	13%
2019	8%	6.1%	7.6%	14%
2020	9%	6.1%	7.9%	14%
2021	10%	6.1%	8.3%	14%
2022	12%	6.1%	8.8%	15%
2023	13%	6.1%	9.2%	15%
2024	14%	6.1%	9.7%	16%
2025	14%	6.1%	10.2%	16%
2026	15%	6.1%	10.7%	17%
2027	16%	6.1%	11.3%	17%
2028	17%	6.1%	11.9%	18%
2029	17%	6.1%	12.5%	19%
2030	18%	2.7%	13.1%	16%

The decrease in the discount rate decreases Column B. Column B is the benefit of waiting. The discount rate plus the solar cost declines contribute to the benefit of waiting one year to install solar. Column C also contributes to the benefit of installing solar and it increases as a result of the discount rate decreasing. Column C is the profit that the customer will earn in the x + 25 year if they delay the solar investment. The decrease in the discount rate increases the present value of the future earnings associated with delaying the investment. This increase is high enough that it more than covers the reduced benefit in Column B. This means that the benefit of waiting increases with a 4.8% discount rate and this results in an increased incentive to wait for those customers.

On an energy basis the low discount rate results in 8766 GWh of solar production in 2030. This is 9 percent of total energy consumption in Alberta in 2030, forecast by the AESO in their 2017 long term outlook.[115]

Figure 9 - Rooftop Solar Adoption With 4.8 Percent Nominal Discount Factor



It is the flattening out of solar costs in 2031 that incents the installation of solar in 2030. With continued cost declines the customers would be incented to continue waiting past 2030. Table 20 shows the year that adoption occurs with and without the incentive to wait included in the

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115 8766 / 94304 = 0.09 ibid.

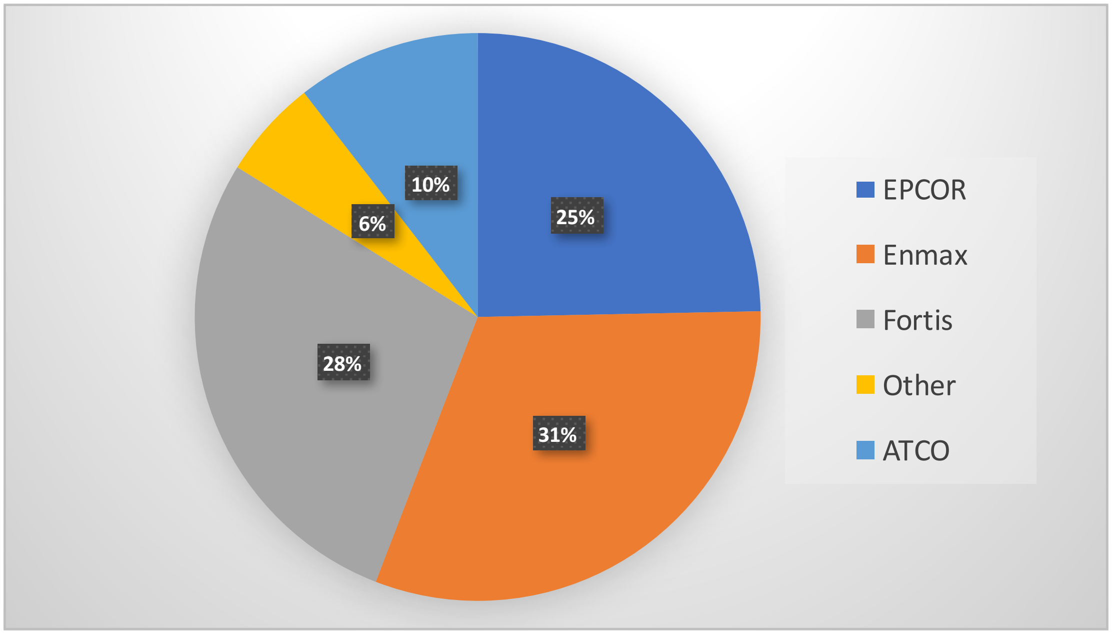
customer's decision. The low discount rate brings the immediate adoption year (adoption without considering the incentive to wait) to 2017 but the increased incentive to wait pushes the adoption year out to 2030 and beyond for all DFO service areas.

Table 20 - Immediate Adoption Year Versus Delayed Adoption Year (4.8% Nominal Discount Rate)

		Quintile		
	Immediate/ Delayed Adoption year	5th	4th	3rd
Serice Area	ATCO	2017/2030	2017/2030	2017/2030
	Fortis	2017/2030	2017/2030	2017/2030
	Enmax	2017/2030	2020/2030	2022/DNS
	Epcor	2017/2030	2019/2030	2021/2030
	DNS stands for 'Does Not Substitute'			

Figure 10 - Residential Electricity Sites by Distribution Company (2017)[116]

[116] Market Surveillance Administrator (2016). "2016-06-30 MSA Retail Market Statistics." Retrieved November 29th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-06-30_MSA_retail_market_statistics.xlsx.



Another sensitivity analysis is increasing the nominal discount rate to 12.75 percent. Increasing the nominal discount rate to 12.75% significantly reduces the incentive to install solar. In 2030 the installed capacity of solar is 2965MW. ATCO adoption is pushed out to 2027. Fortis adoption is pushed out to 2030 and Epcor and Enmax do not substitute in 2030.

In the 12.75% discount rate scenario, the higher discount factor decreases the incentive to install solar. Future earnings from solar are worth less and this decreases the incentive to install. A mitigating factor to this is that the incentive to wait also decreases. This is why the adoption for ATCO customers using the 12.75% discount rate occurs earlier than the 4.8% nominal discount rate scenario. Overall the incentive to install solar is less under the 12.75% discount rate scenario, but the incentive to wait is also decreased. The reduced incentive to wait incents ATCO customers to install solar earlier under the 12.75% discount rate compared to the 4.8% discount rate.

The incentive to wait for ATCO's 5th quintile is shown in Table 21. The increased discount rate decreases the value of the profits earned in the x +25 year and this decreases the benefit of waiting. This effect is listed in Table 21 under Column C. The decreased benefit of waiting in Column C is partially mitigated by the increase in Column B. Column B in Table 21 increases because the interest rate increased.

Overall the impact of the 12.75% discount rate is that it decreases the incentive to wait. The increased incentive to wait from Column C more than offsets the decreased incentive in Column B (Table 21).

Table 21 - ATCO's 5th Quintile Incentive to Wait (12.75% Discount Rate)

	Column A	Column B	Column C	Column D
Year(x)	Profit(x)/K(x)	q+r	Profit(x+25) / (1+r)^(25) / K(x)	Column B plus Column C
2017	7%	13.9%	1.1%	15.0%
2018	8%	13.9%	1.2%	15.0%
2019	8%	13.9%	1.2%	15.1%
2020	9%	13.9%	1.3%	15.2%
2021	10%	13.9%	1.3%	15.2%
2022	12%	13.9%	1.4%	15.3%
2023	13%	13.9%	1.5%	15.4%
2024	14%	13.9%	1.6%	15.4%
2025	14%	13.9%	1.6%	15.5%
2026	15%	13.9%	1.7%	15.6%
2027	16%	13.9%	1.8%	15.7%
2028	17%	13.9%	1.9%	15.8%
2029	17%	13.9%	2.0%	15.9%
2030	18%	10.5%	2.1%	12.7%

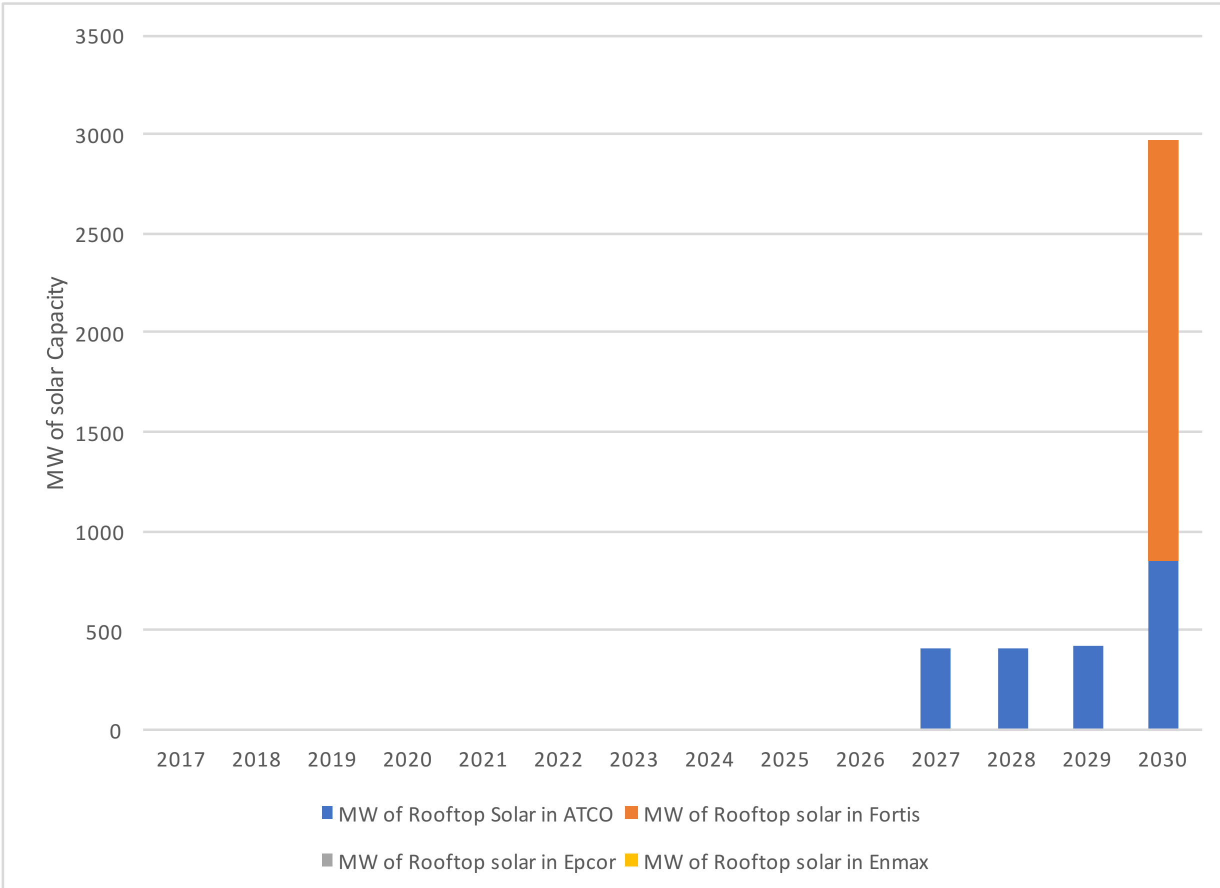
Table 22 shows the impact of the incentive to wait for all DFO service areas using a 12.75% discount rate. After including the incentive to wait none of EPCOR or Enmax's customers have an incentive to install solar by 2030. Fortis and ATCO's service area also gets pushed out as a result of the higher discount rate.

Table 22 - Immediate Adoption Year Versus Delayed Adoption Year (12.75% Nominal Discount Rate)

		Quintile		
	Immediate/ Delayed Adoption year	5th	4th	3rd
Serice Area	ATCO	2019/2027	2021/2030	2024/2030
	Fortis	2022/2030	2026/2030	2029/DNS
	Enmax	2029/DNS	DNS/DNS	DNS/DNS
	Epcor	2029/DNS	DNS/DNS	DNS/DNS
	DNS stands for 'Does Not Substitute'			

The higher discount rate is meant to test the impact of solar being a high risk investment. It is possible that residential customers consider rooftop solar to be a high risk investment and they require a high rate of return to justify the installation of solar panels. The risk associated with installing rooftop solar is that the prices on the grid could change. The customer faces some risk that the assumption they have made on what the future price of continuing to purchase electricity from the grid are not correct. Increasing the interest rate by four percent is meant to address that risk. Figure 11 shows the outcome of a higher discount rate.

Figure 11 - Rooftop Solar Forecast with 12.75% nominal discount rate

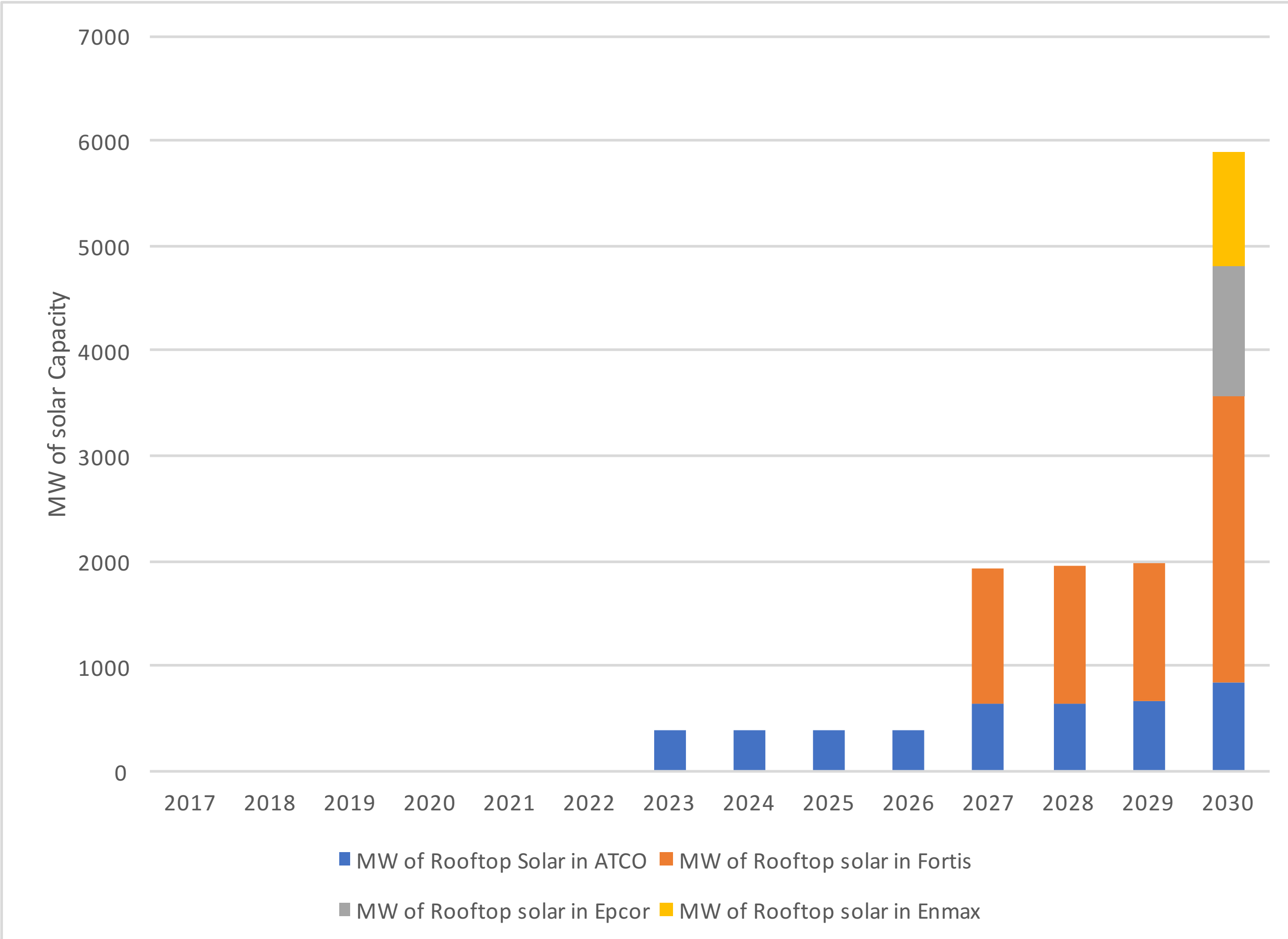


ATCO's 5th quintile substitutes in 2027 adding 408 MW of rooftop solar. This is followed by ATCO's 4th and 3rd quintiles in 2030. The 4th and 3rd quintiles add 430 MW to ATCO's solar adoption in 2030. Fortis 4th and 5th quintiles also substitute in 2030. The Fortis customers add 2110 MW of solar capacity. The adoption of Fortis customers in 2030 is driven by the assumed flattening out of solar cost declines in 2030. The flat solar costs in 2030 decreases Fortis customers' incentive to wait in 2030 enough that they choose to substitute in that year.

The last sensitivity analysis done on the solar forecast is testing how flat distribution prices (on a real basis) after 2030 would impact the forecast. Increasing distribution prices are a driver of the incentive to wait to install solar. Customers see that the profits associated with installing a solar panel are increasing and this increases the incentive to wait to adopt solar. If a customer can earn more money if they delay discounted back to today, they will delay the investment.

The average annual growth rate of nominal distribution tariffs are forecast to increase by 5% from 2030 to 2055. The average annual growth rate of nominal transmission tariffs are forecast to increase by 2.0% from 2030 to 2055. This means that the distribution charge is forecast to exceed inflation into the future and transmission charges are forecast to grow at the level of inflation. The sensitivity tests what would happen to the incentive to install solar if the average annual growth rate of the nominal distribution charge was set to 2%.

Figure 12 - Rooftop Solar Forecast with Flat Distribution Charge After 2030



Keeping distribution tariff growth capped to inflation 2030 and onward incents ATCO and Fortis customers to substitute earlier. ATCO customers install three years earlier relative to the reference case and Fortis customers install one year earlier relative to the reference case. The incentive to wait to install solar is decreased as a result of the lower distribution charges past 2030. High future distribution charges incent customers to wait to install solar because the high future distribution charges increase their return in those years. With lower future distribution charges the returns from waiting to install fall and customers install earlier as a result.

The sensitivities show how the forecast would change if assumptions are adjusted. Reducing the cost of solar has the biggest impact on the solar forecast. Increasing the discount rate will decrease the solar forecast in 2030 due to the reduction of future earnings. Decreasing the discount rate will increase the solar forecast in 2030 due to the increase in future earnings. The decreased distribution tariff forecast shifts solar adoption sooner because of the reduced incentive to wait.

The most important factors influencing solar adoption is the cost of solar and the discount rate. Depending on how solar costs decline and what the residential discount rate is it could change the adoption year by four years in either direction.

The additional layer for the analysis on the timing of solar adoptions is the impact that solar adoptions will have on the level of transmission and distribution charges. The next chapter (Chapter 7) explores this topic, using the reference case as its base. All assumptions explained in Chapter 6 for the base case, including an 8.75% nominal interest rate, Kost's decrease in solar costs and the incentive to wait are used in Chapter 7.

Chapter 7 Solar Death Spiral

7.1 Calculating New Tariff

Customers substituting to solar would have an impact on the level of residential distribution and transmission tariffs. As more residential customers substitute to solar, the volume of electricity consumed by the residential customer class would decrease. This would result in decreasing revenue for residential distribution and transmission services as more solar panels are installed.

Assuming that the distribution company's long-run costs remain the same with more solar panels installed, the lost revenue needs to be recuperated by raising the tariffs.[117] Raising the tariffs increases the incentive to install solar, and this speeds up the process of solar substitution.

The effect of increasing the rate of adoption due to other customers installing solar is sometimes referred to as a death spiral. The effect of the solar substitutions compounds onto itself in that the rate increases from the solar adoptions incent more solar adoptions. The feedback loop can result in the entire network installing solar because of the solar adoption that occurred first.[118]

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[117] Chapter 14 provides estimates of how transmission and distribution costs would be impacted by rooftop solar. For the sake of simplicity, the cost savings from rooftop solar are assumed to be zero in this Chapter. In reality, there are transmission and distribution cost savings associated with solar adoptions. Cost savings on the distribution and transmission network would decrease the tariff increases resulting from solar adoptions.

[118] Felder, F. A. and R. Athawale (2014). "The Life and Death of the Utility Death Spiral."

The transmission and distribution rates that residential customers face are set by the customers' distribution company. Distribution companies' rates are set using performance based regulation. Performance based regulation in Alberta establishes rates that increase at a predetermined rate. After five years, another rate hearing is held and the level of the rates are reset based on costs.[119]

If a distribution company lost a significant amount of electricity consumption from solar installations, they would have the opportunity to re-calculate their rates in a cost-of-service hearing. Depending on when their last cost-of service hearing took place, it could take zero to five years before the next cost-of-service hearing would occur.

This section assumes that a distribution company can recalculate their tariffs every five years. If solar adoptions increase, the distribution company can increase their tariffs to make up for the lost electricity consumption every 5 years. The five year interval is applied to ATCO, Epcor, Enmax and Fortis. The solar costs and discount rate from the reference case are also used for this example.

The transmission and distribution tariff is determined by total costs incurred by the residential rate class and the consumption by residential customers. Total costs are divided by the total kWh's to create the variable charge.[120] The variable charge is charged based on the number of

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[119] Alberta Utilities Commission (2012). "Rate Regulation Initiative: Distribution Performance-Based Regulation." from http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf.

[120] See Chapter 11 for a more detailed description of how residential tariffs are calculated.

kWh consumed. Both the residential transmission and residential distribution tariffs have variable charges.

For this chapter we assume that rooftop solar does not impact the total long-run cost of distribution and transmission. This means that the addition of rooftop solar on the network does not increase or decrease the total costs faced by distribution and transmission companies. The only factor that changes is the kWh's that the distribution or transmission company can charge residential customers. The impact of rooftop solar on distribution and transmission long-run costs is covered in Chapter 14.

The energy charge for residential transmission and distribution tariffs would increase based on the reduction in consumption by residential customers. As an example, the installation of rooftop solar might results in a 39 percent decrease in energy consumption by residential customers. The 39 percent reduction in revenues would need to be recovered by increasing tariffs. A 64 percent increase in tariffs results in the shortfall in revenues being filled.

This example is shown using formulas. A tariff is calculated by taking the costs allocated to the residential rate class and dividing this by the kWh's consumed. This ensures that when the DFO charges for distribution or transmission, the kWh's multiplied by the per kWh charge equals their costs.

Equation 1:

$\text{Costs} / \text{kWh} = \text{Tariff}_{old}$

'$Tariff_{old}$' refers to the tariff prior to any changes to kWhs consumed.

If the kWh's consumed decreases by 39 percent, this means that there is 0.61 percent remaining:

Equation 2:

Costs / (kWh – (0.39*kWh)) = Costs / (kWh * (1 – 0.39)) = Costs / (kWh *0.61) = $Tariff_{new}$

'$Tariff_{new}$' refers to the recalculated tariff based on the change in the kWh consumed. Then we multiply both sides of the equation by 0.61.

Equation 3:

Costs / kWh = 0.61 * $Tariff_{new}$

We know from Equation 1 that Costs / kWh = $Tariff_{old}$. By equating Equation 1 and Equation 3 we get:

$Tariff_{old} = 0.61 * Tariff_{new}$.

By dividing both sides of the equation by 0.61 we get the following equation.

$(1/0.61)\ Tariff_{old} = Tariff_{new}$

$1.64 * Tariff_{old} = Tariff_{new}$

The new tariff with the 39 percent decrease in kWh is equal to the old tariff increased by 64 percent. This calculation is done for all DFO's to determine the increase in tariffs resulting from a decrease in electricity consumed by customers substituting to solar.

The amount of solar installed determines the change in kWh for residential customers. The more customers adopt solar, the more the distribution and transmission rates increase. The more distribution and transmission tariffs increase the more customers adopt solar.

Once all customers have adopted solar, the distribution company cannot increase the variable portion of the transmission or the distribution tariff to account for lost revenue. In this case, the distribution company would need to increase the fixed charge for distribution and implement a fixed charge for transmission to recover the cost of distribution and transmission. Increasing the fixed charge is covered in more detail in Chapter 12 and Chapter 15.

7.2 ATCO Scenario

In 2026 the fifth quintile of ATCO customers substitute. This will reduce the volume of electricity consumed from ATCO's distribution network. It is assumed that tariff hearings occur on a 5 year interval (this is based on the schedule of performance based regulation hearings in Alberta). If ATCO has a hearing in 2017, the following hearings would occur in 2023 and 2028. In 2028 , ATCO would have the opportunity to raise their rates in response to the decreased electricity sales caused by ATCO customers substituting to solar in 2026. It is assumed that the tariff would increase in 2028 to make up for the lost revenue caused by ATCO's 5th quintile substituting in 2026. ATCO's 5th quintile uses 39 percent of ATCO's service areas electricity. Using the formula from section 7.1, if ATCO lost 39 percent of their electricity sales to solar adoption they would need to increase their tariffs by a factor of 1.64 (1/(1-0.39)=1.64).

Without the tariff increases caused by the 5th quintile substituting in 2026, ATCO's 4th quintile would have an incentive to substitute to solar in 2029. The 2029 substitution date includes the incentive to wait for lower solar costs in the future. The increase in the tariff from the rate hearing in 2028 would incent ATCO's 4th quintile to substitute in 2028. The tariff increases are large enough that ATCO's 4th quintile is incented to substitute earlier. The higher transmission and distribution tariffs create larger cost savings associated with installing solar and ATCO's 4th quintile substitutes as a result. The incentive to wait also increases as a result higher future solar earnings but this effect is not large enough to offset benefit of installing in 2028.

ATCO's 3rd quintile also substitutes earlier as a result of the tariff increase in 2028. The increased tariffs in 2028 incents ATCO's 3rd quintile to substitute in 2028. This is two years earlier than they would have without the tariff increases.

The result of the tariff increases is that those customers that are able to install solar install earlier. The incentive to install solar increases and those customers left on the network respond to the tariff increases by adopting solar earlier. Those customers that are not able to install solar (1st and 2nd quintiles) are left with higher transmission and distribution tariffs. Remember that the 1st and 2nd quintiles cannot install solar because most of these customers live in attached housing units where the customer does not own the roof of the building. In ATCO's case the 5th, 4th and 3rd

quintiles account for 78 percent of the electricity sales for ATCO. Using the formula in section 7.1, the tariffs for the 1st and 2nd quintiles would need to increase by a factor of 4.54.

7.3 Fortis Scenario

Fortis' 5th quintile substitutes to solar in 2028. Assuming that Fortis' tariff hearings occur at the same interval as ATCO's there would be a rate hearing in 2028. Fortis' 5th quintile consumes 39 percent of Fortis' electricity. The substitution of Fortis' 5th quintile would decrease electricity sales in Fortis' service area by 39 percent. Using the formula in section 7.1 the decrease in consumption would require the variable transmission and distribution tariffs to increase by a factor of 1.64.

The increase in distribution and transmission tariffs in 2028 would incent Fortis 4th quintile to substitute two years earlier. Without the tariff increases caused by Fortis' 5th quintile substituting, Fortis 4th quintile would substitute in 2030. The higher transmission and distribution tariffs increase the profits associated with installing rooftop solar this incents Fortis' 4th quintile to substitute in 2028.

Fortis 3rd quintile's substitution date is left unchanged by the increased tariff. With or without the tariff increases, Fortis' 3rd quintile substitutes in 2030. This is due to Fortis' 3rd quintile's incentive to wait. The impact of the increased returns from installing solar and the incentive to wait for Fortis' 3rd quintile is shown in Table 23.

Table 23 - Comparing Incentive to Install Solar With and Without Tariff Increases Caused by Solar Adoptions (Fortis 3rd Quintile)

	Without Tariff Increase from Solar Substitution			With Tariff Increase from Solar Substitution		
	Column A	Column B	Column C	Column D	Column E	Column F
Year(x)	Earnings from Solar	Benefit of Waiting to install	Cost of waiting to install	Earnings from Installing Solar	Benefit of Waiting to install	Cost of waiting to install
2017	($4,330.58)	11.4%	3.8%	($2,858.03)	11.8%	3.8%
2018	($3,255.00)	11.5%	4.6%	($1,610.07)	11.9%	4.6%
2019	($2,291.73)	11.5%	4.8%	($461.77)	11.9%	4.8%
2020	($1,328.97)	11.6%	5.5%	$699.55	12.0%	5.5%
2021	($455.09)	11.7%	6.0%	$1,786.47	12.1%	6.0%
2022	$368.01	11.7%	7.4%	$2,838.05	12.2%	7.4%
2023	$1,003.59	11.8%	7.9%	$3,718.64	12.3%	7.9%
2024	$1,588.45	11.9%	8.2%	$4,566.16	12.4%	8.2%
2025	$2,158.84	12.0%	8.3%	$5,418.08	12.5%	8.3%
2026	$2,757.72	12.1%	9.0%	$6,318.65	12.7%	9.0%
2027	$3,281.16	12.1%	9.4%	$7,165.29	12.8%	9.4%
2028	$3,793.78	12.2%	9.7%	$8,024.14	12.9%	12.1%
2029	$4,296.41	12.3%	10.1%	$8,580.82	13.1%	12.6%
2030	$4,789.84	9.1%	10.5%	$9,131.35	9.9%	13.0%

Column A in Table 23 is the present value of the earnings that the customer can earn over 25 years from installing solar. Column D is the same earnings but with increased transmission and distribution tariffs caused by the 5th quintile substituting to solar. The increase in the transmission and distribution tariffs increases the returns associated with installing rooftop solar. Net earnings become positive in 2022 without the tariff increases and 2020 with the tariff increases.

Column B and C consider the incentive to wait. Column A and D show when the customer would install solar if they do not consider the incentive to wait. The incentive to wait pushes the substitution date well beyond 2020 and 2022. Column B is the benefit of waiting to install solar (discount rate plus the cost decline in the following year plus the profits earned in the x + 25 year). Column C is the cost of waiting (the profits lost from delaying one year). Column E and F are the same as Column B and C except that they include higher transmission and distribution tariffs created from solar substitutions. The incentive to wait is high enough with the tariff increases to delay the solar investment to 2030. Even though the customer earns positive earnings two years earlier (2020 from 2022) the incentive to wait is high enough that the substitution date is still pushed out to 2030.

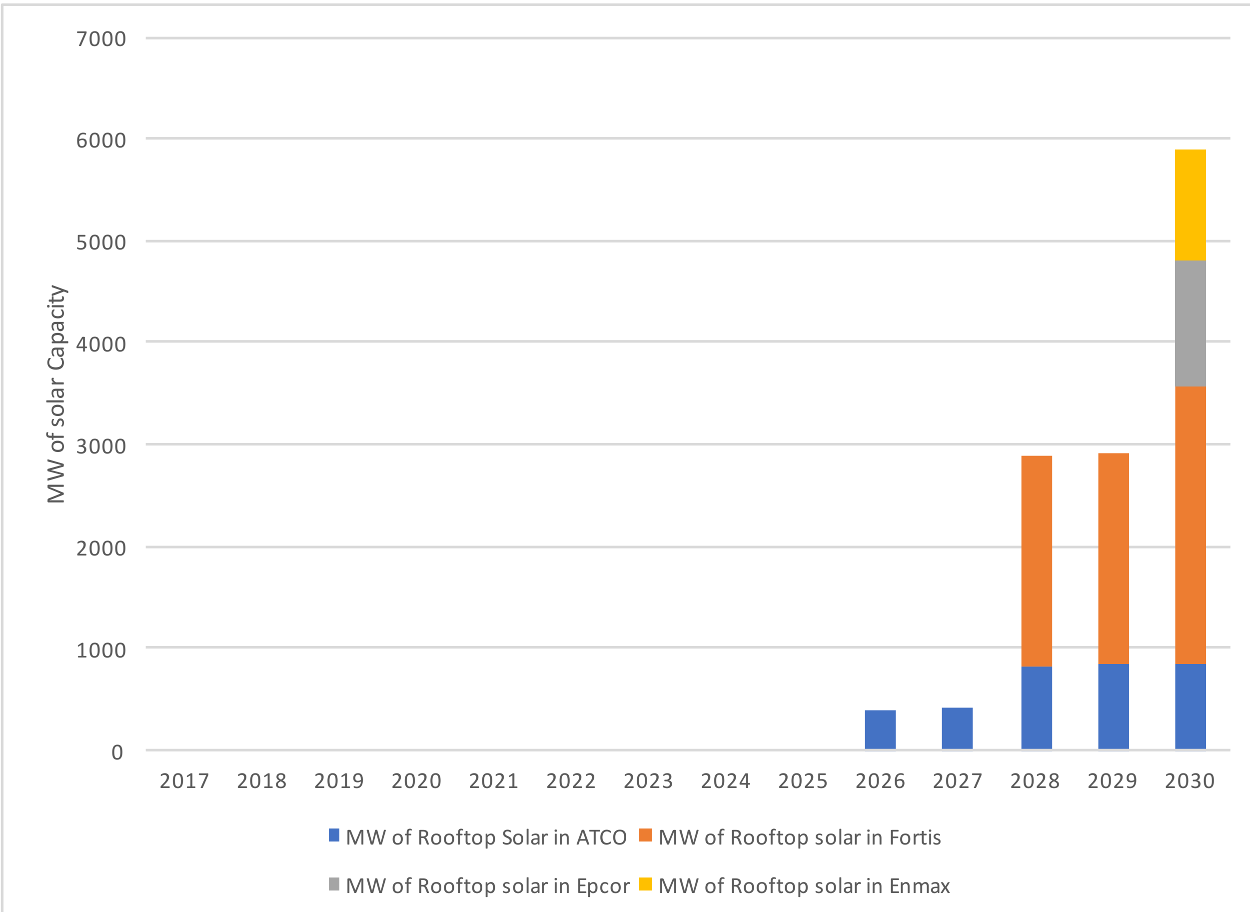
Fortis 1st and 2nd quintiles do not substitute to solar because these customers are likely to live in attached housing where installation of rooftop solar is not possible. The solar adoptions by the 5th, 4th and 3rd quintiles would have a big impact on the transmission and distribution tariffs of the 1st and 2nd quintiles. The substitution of the 5th , 4th and 3rd quintiles by 2030 would decrease the electricity sales for Fortis by 78 percent. The remaining 22 percent of electricity sales on the network (1st and 2nd quintiles) would experience tariff increases by a factor of 4.54 (1/(1-0.78)=4.54).

7.4 Epcor and Enmax Scenarios

Epcor and Enmax customers substitute in 2030. The 5th quintile of Enmax substitutes in 2030 resulting 1060 MW of rooftop solar installations. The 5th quintile of Epcor also substitutes in 2030 resulting in 800 MW of solar installations. Assuming the 5 year interval for tariffs hearings, if Enmax and Epcor had a tariff hearing in 2028, their next tariff hearing would occur in 3033.

This is beyond the time frame of the forecast. Using Fortis and ATCO as an example the tariff increases in Enmax and Epcor would likely accelerate solar adoption in the years beyond 2030.

Figure 13 - Alberta Residential Rooftop Adoption with Tariff Increases



In aggregate the total solar capacity by 2030 as a result of the tariff increases is 5878 MW. This is the same as the reference case. The impact of the tariff increases is that ATCO and Fortis customers substitute earlier than they otherwise would have.

7.5 Impact of Tariff Increases

The key finding from increasing tariffs from solar adoption is that tariff increases accelerate the timing of solar adoptions for remaining non-solar customers within the same service area. For ATCO and Fortis this leads to customers substituting to solar earlier than they otherwise would have.

If a portion of a service area substitutes to solar, it incents the remaining customers in the service area to substitute sooner. This was the case for ATCO and Fortis. In ATCO and Fortis service area, once substitution occurred in 2026 and 2028 the other quintiles substituted sooner.

This analysis does not consider the potential cost savings that rooftop solar can provide to transmission and distribution. Cost savings would decrease the tariff increase associated with rooftop solar adoption because the size of the revenue requirement would decrease. Chapter 14 covers what the cost savings associated with rooftop solar are and Chapter 15 applies those cost estimates to Alberta.

Solar adoptions that are caused by tariff increases described in this chapter are undesirable because the adoptions are not being driven by the cost of solar or the cost of transmission and distribution. The solar adoptions are being driven by other customers substituting and increasing tariffs as a result.

The impact of the death spiral is mitigated in Alberta's residential electricity sector by the separate revenue requirements of Alberta's distribution companies. Solar adoptions impact the level of the tariff in a specific distribution company's service area, but the impact does not spill over to other distribution companies. If ATCO loses revenue it does not impact the rates in Fortis, Enmax or Epcor's service area.

Even transmission costs are isolated to each distribution company. Each distribution company pays for their connection to the transmission network through the Demand Transmission Service (DTS) tariff. If a distribution company loses transmission revenues from residential customers then the residential transmission tariff would need to increase in the affected service area. Tariffs in other service areas would not be impacted.

If tariff increases in the ATCO service area impacted tariffs in Enmax and Epcor, then the impact of the death spiral would be much greater. Enmax does not substitute by 2030 because solar costs do not fall sufficiently to incent those Enmax customers to substitute before then. If ATCO's substitutions increased Enmax's rates, then it could incent Enmax to adopt even earlier than 2030. Fortunately, solar adoptions in ATCO's service area have no impact on Enmax's distribution or transmission tariffs.

It was assumed in this chapter that the cost of transmission and distribution are not changing as a result of the solar adoptions. Despite this assumption, the tariff increased as a result of more solar adoptions on the network. The tariff increases that occur with the current tariff structure are a result of tariff design. Less electricity being consumed from the network necessitates a rate increase. A tariff that is properly designed responds to changes in the long-run marginal cost. Chapter 12 covers a tariff structure based on the long-run marginal cost of transmission and distribution and Chapter 15 covers how it would impact solar adoptions in Alberta. This chapter shows that if the current tariff structure is maintained, solar adoptions within a service area will accelerate the adoption rate of the remaining customers.

The inefficiency calculation in Chapter 15 uses the solar adoption rate forecast from Chapter 6. Using the solar adoption rate forecast from Chapter 7 would increase the inefficiency associated with solar because solar adoptions occur more quickly as a result of the tariff increases.

Chapter 8 Disconnection Death Spiral

There are two different types of death spirals that can occur from the adoption of solar. The first is the introduction of solar without storage. This scenario was covered in Chapter 7. The substitution of customers to solar incents additional substitutions until the entire network has adopted the new technology.[121]

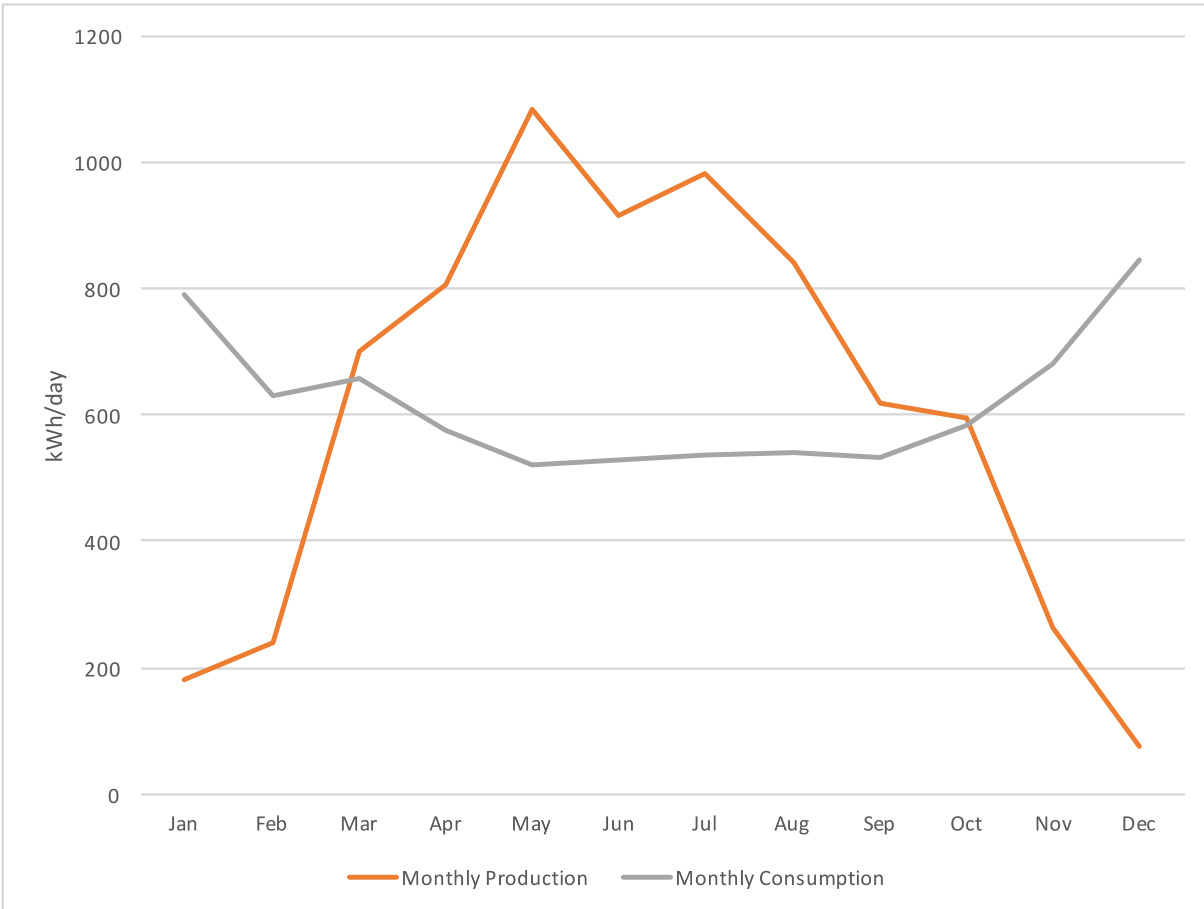
Another type of solar death spiral is the disconnection death spiral. This is when solar customers install solar and storage in and on their houses such that they can fully disconnect from the grid. Complete disconnection from the grid has the same effect, but on a larger scale. Complete disconnection means that the DFO's also lose the fixed charge for distribution when a customer decides to disconnect from the grid.

8.1 Storage Economics

The ability to store electricity on-site would allow for the possibility of residential customers disconnecting from the grid and relying solely on their own solar panels for power. The problem in Alberta is that solar production is well below energy consumption for households in November, December, January and February. Electricity consumption increases in the winter months and solar production experiences a significant decline.

[121] Felder, F. A. and R. Athawale (2014). "The Life and Death of the Utility Death Spiral."

Figure 14 - 2015 Edmonton Solar Production vs ATCO Electric Consumption



[122]

The graph shows the solar production from a system (5.7 kW) that has a large enough capacity to offset the average ATCO customer (average of 619 kWh per month) over the course of one year.

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[122] Daily consumption data source: ATCO Electric. "Sample Profiling Data & Information." Retrieved November 17th, 2016, from http://www.atcoelectric.com/Services/retailers/Sample-Profiling-Data-and-Information.

Solar production source: NAIT Alternative Energy Program (2015). " NAIT Reference Array Report March 31, 2015 (revB)." from https://solaralberta.ca/sites/default/files/NAIT%20Reference%20Array%20Report%20March%2031%2C%202015%20%28revB%29.pdf.

The storage required to transfer electricity produced in sunnier summer months to the winter months is far greater than what current technologies can provide. Tesla's 'Powerwall 2' has 13.5 kWh of usable capacity.[123] 2170 kWh's of electricity would need to be stored to allow the average ATCO Electric household to remain off grid for the winter months. It would require 161 Powerwalls to store 2170 kWh of electricity.[124] Given that this type of storage is unrealistic, the average ATCO customer would need to source electricity from the grid in the winter months.[125]

Table 24 shows the monthly production of a 5.7 kW system in Edmonton and the average electricity use of an ATCO Electric customer. The table shows the same results as Figure 14. The kWh deficit and surplus is listed under the 'Difference' column. The deficit in the winter results in the customer consuming more electricity than they produce in January, February, November and December.

Table 24 - Electricity Production and Consumption of a 5.7 kW Solar System[126]

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[123] Tesla. "Powerwall 2." Retrieved December 1st, 2016, from https://www.tesla.com/en_CA/powerwall.

[124] 2170 kWh / 13.5 kWh = 161

[125] Using the production numbers from Northern Alberta Institute for Technology (NAIT) and the consumption numbers for the average ATCO customer, March to October are surplus months (more electricity is produced than is consumed) and November to February are deficit months (more electricity is consumed than is produced). In order to disconnect from the grid, the average ATCO customer would need to store 2170 MWh over March to October to be consumed over November to February.

[126] Monthly consumption data source: ATCO Electric. "Sample Profiling Data & Information." Retrieved November 17th, 2016, from http://www.atcoelectric.com/Services/retailers/Sample-Profiling-Data-and-Information.

Monthly solar production source: NAIT Alternative Energy Program (2015). " NAIT Reference Array Report March 31, 2015 (revB)." from https://solaralberta.ca/sites/default/files/NAIT%20Reference%20Array%20Report%20March%2031%2C%202015%20%28revB%29.pdf.

	Monthly Consumption (KWh)	Monthly Production (KWh)	Difference
Jan	792	183	-609
Feb	632	240	-391
Mar	656	702	46
Apr	576	805	228
May	521	1084	563
Jun	528	917	389
Jul	537	982	445
Aug	539	841	302
Sep	532	618	87
Oct	583	596	13
Nov	681	264	-417
Dec	846	75	-771

Another possibility to disconnect from the grid would be to install larger solar systems on houses. This would allow for enough production to occur in the winter months to satisfy the household's consumption.

Even if larger systems were permissible in Alberta, rooftop solar is restricted by the amount of roof space available. The 0.23 kW solar panels used to create the data in Table 24 are 1.652 meters squared.[127] The average floor space area for a new home in 2012 in Canada was 181 meters squared.[128] If the average household rooftop is 90.5 meters squared and it is entirely covered with 0.23 kW solar panels, the system would have 12.6 kW of capacity.[129] 12.6 kW of capacity still falls short of consumption in the months of January, February, November and December. The deficit that occurs with a 12.6 kW system in January, February, November and December is shown in Table 25.

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[127] Affordable Solar. "Conergy P 230PA, 230W Solar Panel." Retrieved November 18th, 2016, from http://store.affordable-solar.com/store/discontinued-unavailable-solar-panels/Conergy-Silver-P230PA-230-watt-Solar-Panel.

[128] Wilson, L. "How big is a house? Average house size by country." Retrieved December 1st, 2016, from http://shrinkthatfootprint.com/how-big-is-a-house.

[129] 90.5 square meters of roof space / 1.652 square meters per solar panels = 54.8 panels. 54.8 Panels * 0.23 kW of capacity per panel = 12.6 kW.

Table 25 - Rooftop Solar Adoption by 12.6 kW system[130]

	Monthly Consumption (KWh)	Monthly Production (KWh)	Difference
Jan	792	400	-392
Feb	632	526	-106
Mar	656	1537	881
Apr	576	1762	1185
May	521	2373	1852
Jun	528	2008	1480
Jul	537	2150	1613
Aug	539	1841	1302
Sep	532	1354	822
Oct	583	1305	722
Nov	681	578	-103
Dec	846	164	-682

It would require huge leaps in storage and/or solar production efficiencies to allow residential customers to fully disconnect from the network. This paper assumes that these technological advances are not plausible over the next 15 years.

8.2 Summary

[130] Monthly consumption data source: ATCO Electric. "Sample Profiling Data & Information." Retrieved November 17th, 2016, from http://www.atcoelectric.com/Services/retailers/Sample-Profiling-Data-and-Information.

Monthly solar production source: NAIT Alternative Energy Program (2015). " NAIT Reference Array Report March 31, 2015 (revB)." from https://solaralberta.ca/sites/default/files/NAIT%20Reference%20Array%20Report%20March%2031%2C%202015%20%28revB%29.pdf.

Solar adoptions in Alberta will grow over time as customers in each distribution service area switch over to solar power. ATCO will lead, followed by Fortis, Epcor and Enmax.

The current rate structure has a big impact on the solar adoption rate in Alberta. This impact is demonstrated by the difference in substitution dates between distribution company service areas. Service areas like ATCO and Fortis that have high energy transmission and distribution tariffs will be the first to adopt. Enmax and Epcor are later due to their low distribution and transmission tariffs.

Rate increases from customers adopting solar will increase the rate in which solar is adopted in Fortis and ATCO's service areas. It will also accelerate the adoption rate for Epcor and Enmax.

The current rate structure incents between 2965 MW and 5878 MW of rooftop solar by 2030, depending on the discount rate used. 2965 MW or 5878 MW of rooftop solar is an efficient level of solar provided that the prices that incented those installations are properly set. Transmission and distribution tariffs have a big impact on the incentive to install rooftop solar. If the current transmission and distribution tariffs are at the correct level and structure, then customers will be incented to install an efficient level of solar. If not, then transmission and distribution tariffs need to be adjusted and this will change the amount of rooftop solar installed accordingly.

Cost allocation is the guiding principle of the current tariff structure for transmission and distribution. Chapters 9, 10 and 11 cover the cost allocation process that creates the current transmission and distribution tariffs. This cost allocation structure is then compared to marginal cost pricing in Chapter 12. The current cost tariff structure created by cost allocation matches the marginal cost tariff structure for distribution. The current tariff structure for transmission does not match the marginal cost tariff structure. The cost allocation process is covered in the next chapter.

Chapter 9: Cost Allocation of Transmission and Distribution Costs

Cost allocation is the first step in determining residential transmission and distribution tariffs in Alberta. This chapter covers Alberta's cost allocation methods to show how prices are determined for residential transmission and distribution companies.

The electricity transmission and distribution industries follow a series of steps to determine how transmission and distribution costs get passed on to residential customers. The process of determining what costs get allocated to each customer class is called 'cost allocation'.

Residential customers are those that receive the residential tariff through their distribution company. The residential tariff differs from the commercial and industrial tariffs. The residential tariff for Enmax, Fortis, ATCO, and Epcor are applied to single and separated households that have their own meter.[131] This would include single family detached housing, and attached housing units where each housing unit has its own meter (Condos and apartments). Some existing condos and apartment buildings only have one meter for the entire building. In this case

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[131] Enmax (2016). "ENMAX POWER CORPORATION ("EPC") DISTRIBUTION TARIFF RATE SCHEDULE." Retrieved August 23rd, 2016, from https://www.enmax.com/ForYourHomeSite/Documents/2016-07-01-DT-Rate-Schedule.pdf.
, FortisAlberta Inc. (2016). "FORTISALBERTA INC. 2016 ANNUAL RATES FILING RATES, OPTIONS, AND RIDERS SCHEDULES October 1, 2016." Retrieved October 6th 2016, from http://fortisalberta.com/docs/default-source/default-document-library/2016-oct-rates-options-riders-schedules.pdf?sfvrsn=6.
, ATCO Electric (2016). "ATCO Electric Price Schedule Index." Retrieved October 7th, 2016, from http://www.atcoelectric.com/Rates/tariffs/Documents/2016%20Tariffs/2016-01-01%20AE%20Price%20Schedules.pdf.
, Epcor (2016). "DT – Schedule 1Distribution Access Service Tariff ". from http://www.epcor.com/power-natural-gas/Documents/DistributionAccessServiceTariff-2016-01.pdf.

the building would be charged based on the commercial rate.[132] This paper focuses exclusively on the residential rate class and the forecast in Chapter 6 is for all customers that use the residential rate.

Residential customers pay for transmission and distribution through their distribution facility owner (DFO). A DFO delivers electricity to customers from the transmission network.

Alberta has four major DFOs: Enmax, Epcor, FortisAlberta and ATCO Electric. A residential customer's location determines their distribution company. Northern and eastern Alberta are served by ATCO Electric. Calgary is served by Enmax Power Corp. Edmonton is served by EPCOR Distribution Inc. Southern and central Alberta are served by FortisAlberta Inc.[133]

Alberta's residential customers pay for transmission through their local distribution company. The charge is based on the volume of electricity they consume. Enmax, Epcor, Fortis and ATCO Electric all have different prices for transmission, but they all charge based on volume of electricity consumed.

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[132] FortisAlberta Inc. (2016). "FORTISALBERTA INC. 2016 ANNUAL RATES FILING RATES, OPTIONS, AND RIDERS SCHEDULES October 1, 2016." Retrieved October 6th 2016, from http://fortisalberta.com/docs/default-source/default-document-library/2016-oct-rates-options-riders-schedules.pdf?sfvrsn=6.

[133] Alberta Utilities Commission. "Who We Regulate." Retrieved January 24th, 2017, from http://www.auc.ab.ca/about-the-auc/who-we-regulate/Pages/default.aspx.

Rural electrification associations also provide distribution services to some rural communities in Alberta. This paper groups customers served by rural electrification association with Fortis.

Local distribution companies charge for their distribution services based on volume of electricity consumed as well as a fixed monthly charge. Each DFO has a different price for distribution services, but all four companies employ a fixed/variable structure.

9.1 Transmission – Demand Transmission Service (DTS) Tariff

The focus of this paper is the design of the final rate to be paid by residential customers. The establishment of a revenue requirement and the apportionment of costs using fully distributed cost (FDC) pricing are reviewed as building blocks to the final tariff.

The AUC creates Alberta's transmission tariffs using a cost of service regulatory model. The cost of service regulatory model follows three major steps: establishment of a revenue requirement for transmission companies, apportionment of costs to the various rate classes that access the transmission system, and design of the final rate to be paid by applicable consumers.[134]

The apportionment of costs to the various rate classes is done using fully distributed cost (FDC) pricing. Fully distributed cost pricing is a strategy for allocating costs using accounting data. It assumes that some costs can be specifically allocated to a specific service, and the rest are common costs. Chapter 12 introduces marginal cost pricing as an alternative to fully distributed

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[134] Market Surveillance Administrator (2014). "Alberta Retail Markets for Electricity and Natural Gas A description of basic structural features." Retrieved September 28th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/00-2014/Alberta%20Retail%20Markets%20for%20Electricity%20and%20Natural%20Gas%20071714..pdf.

cost pricing. Instead of determining what costs can be allocated to a specific service, marginal cost pricing uses the incremental cost of producing the last unit of the good and charges all customers based on this rate.

When allocating transmission costs, there are some additional steps to the three major ones outlined above. Alberta's transmission system is owned by transmission facility owners (TFO) but it is planned and operated by the AESO.[135] For this reason, the AESO applies to the AUC to approve the tariffs used to reimburse the TFO's.[136] Also, the residential transmission tariff is administered by the distribution facility owner (DFO) and not the AESO, so there are additional steps to connect the AESO's tariff to the residential transmission tariff.

The AESO has nine different tariffs for different types of transmission customers in Alberta. The Demand Transmission Service (DTS) tariff is applied to owners of electric distribution systems (DFO) and larger industrial customers.[137] The DTS tariff gets passed on to residential customers through the DFO.

[135] Alberta Electric System Operator. "Who pays for the transmission system in Alberta?". Retrieved June 14th, 2016, from http://www.aeso.ca/downloads/Who_pays_for_transmission_one_pager.pdf.

[136] AESO (2014). "2014 ISO Tariff Application and 2013 ISO Tariff Update." Retrieved November 27th, 2015, from http://www.aeso.ca/downloads/Decision_2014-242_AESO_2014_ISO_Tariff_and_2013_Update_(2014-08-21).pdf.

[137] AESO (2016). "ISO Tariff – Rate DTS Demand Transmission Service." Retrieved October 14th, 2016, from https://www.aeso.ca/assets/documents/AESO-2016-ISO-Tariff-Rate-DTS-2016-04-01.pdf.

The AESO's revenue requirement includes costs related to wires, ancillary services, transmission line losses and the AESO's administration costs.[138] The revenue requirement is the total revenue that a regulated company can earn to cover its costs.[139] In this case the regulated company is the AESO which reimburses the TFO's.

Transmission line losses are the energy lost when electricity is transported on transmission lines, from generation to the distribution networks.[140] Ancillary services are electricity procured to maintain reliability on the transmission grid.[141]

The DTS tariff contributes to the costs related to wires, ancillary services, and the AESO's administration costs relating to transmission. Line losses are not recovered from DTS customers. The AESO recovers the cost of line losses from generating units, exporters and importers of electricity and opportunity service customers.[142]

The DTS tariff is the first step in determining what transmission costs are allocated to residential customers. It is the mechanism that allocates transmission costs between DFOs, which then

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[138] AESO (2014). "2014 ISO Tariff Application and 2013 ISO Tariff Update." Retrieved October 17th, 2016, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2014/2014-242.pdf.

[139] Regulation Body of Knowledge 3. "Revenue Requiremnts ". Retrieved October 14, 2016, from http://regulationbodyofknowledge.org/glossary/r/revenue-requirements/.

[140] AESO (2016). "Loss Factors." Retrieved March 3rd, 2017, from https://www.aeso.ca/grid/loss-factors/.

[141] Alberta Electric System Operator (2018). "Ancillary Services." Retrieved March 30th, 2018, from https://www.aeso.ca/market/ancillary-services/.

[142] Government of Alberta (2014). ELECTRIC UTILITIES ACT TRANSMISSION REGULATION P. o. Alberta. Edmonton, Alberta's Queen Printer.

eventually gets allocated to residential customers. The structure of the charges used in the DTS tariff are relevant to the final transmission charge for residential customers.

The DTS tariff separates transmission costs into groups and then allocates those groups of costs to different rate classes by the level of electricity demand (consumption during peak times), the volume of electricity consumed, and the number of customers. The three major groups of costs are: bulk, regional and Point of Delivery (POD). The bulk costs are the cost of high voltage lines carrying large amounts of electricity over long distances. The regional costs are the cost of transmitting electricity from the bulk system to load centers. The point of delivery cost covers the cost of connecting distribution networks or industrial customers directly to the transmission network.[143]

Once the Bulk, regional and POD costs are allocated to customer classes, they can be charged to specific customers. The Bulk, regional and POD costs are charges to specific customers using demand, energy and fixed charges. Demand charges are based on the rate of consumption of electricity that is consumed by a customer at peak times. Energy charges are based on the volume of electricity consumed over the billing period (this is the same as the variable charges used by distribution companies). A fixed charge is the same regardless of how much electricity is

[143] AESO (2013). "AESO 2014 ISO Tariff Application and 2013 ISO Tariff Update Negotiated Settlement – Cost Causation Study." Retrieved October 17th, 2016, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2013/2013-421.pdf.

consumed. In aggregate, 69 percent of the DTS tariff is demand charges, 27 percent is energy charges and 4 percent is fixed.[144]

Before the DTS tariff gets passed on to residential customers, a second cost allocation process occurs. The DFO must allocate the DTS charge to its customers.

9.2 DFOs Cost Allocation of the DTS Tariff

The DFOs have their own process of allocating the DTS tariff to their distribution customers. The cost allocation methods used by distribution companies to allocate the DTS tariff are very similar to the DTS tariff itself. Fortis is used to represent all four DFO's cost allocation methods.

Fortis' cost allocation methods for its DTS transmission charges are very similar to the cost allocation methods used in the DTS tariff. The only portion of the DTS tariff that employs a substantially different cost allocation method, as compared to Fortis' cost allocation method, is the POD fixed charge.[145] Fortis allocates the POD fixed charge using a demand charge.

The demand and energy charges used by the AESO and the DFOs to allocate transmission costs are loosely represented in the residential transmission tariff. The fixed charge in the DTS tariff is

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[144] Alberta Utilities Commission (2014). "FortisAlberta Inc. 2012-2014 Phase II Distribution Tariff." from http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-018.pdf.

[145] Ibid.

not represented in the residential transmission tariff. The next section covers the distribution industry’s cost allocation process.

Chapter 10 - Distribution Cost Allocation

Alberta's distribution companies must complete fewer calculations to create residential distribution tariffs, as compared to the transmission industry. Unlike transmission, the distribution company applies to the AUC themselves to approve their revenue requirement and the cost allocation and tariff design they intend to implement.

DFOs use FDC pricing to allocate costs to their rate classes (residential, commercial and industrial). DFOs separate distribution costs into those that can be allocated to a specific service and those that are considered common costs. Common costs are allocated using various cost allocation methods.

The terminology used in the DFO rate hearings requires some explanation. The revenue requirement is the total revenue that a regulated company can earn to cover its costs.[146] The revenue requirement equals the operating costs of the utility plus the rate base and the allowed return.[147] The rate base is the portion of the revenue requirement that the allowed rate of return can be calculated from. The rate base can include working capital and capital under construction.[148]

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[146] Regulation Body of Knowledge 3. "Revenue Requiremnts ". Retrieved October 14, 2016, from http://regulationbodyofknowledge.org/glossary/r/revenue-requirements/.

[147] Regulation Body of Knowledge 2. "Rate of Return Regulation." Retrieved October 14, 2016, from http://regulationbodyofknowledge.org/glossary/r/Rate%20of%20return%20regulation/.

[148] Regulation Body of Knowledge 1. "Rate Base." Retrieved October 14th, 2016, from http://regulationbodyofknowledge.org/glossary/r/rate-base/.

When the assets that make up the rate base are long lived, the regulated firm allocates the cost of the asset over the asset's service life using depreciation.[149] Depreciation payments form a large portion of a DFO's revenue requirement.

DFO's use performance based regulation (PBR) to create tariffs for residential customers. PBR is a form of price-cap regulation. PBR starts with the rates set up by the cost of service model, and then sets the level of subsequent year's rates using a formula. The formula increases rates by the rate of inflation minus a productivity factor. After five years, the rates are re-established using another cost of service hearing.[150]

For the purposes of this paper, PBR and cost of service are equivalent processes because PBR and cost of service regulation have the same method of determining the structure of tariffs. PBR and cost of service differ in how the level of the tariffs changes over time. This paper only covers the structure of tariffs; therefore, its recommendation can be applied to both PBR and cost of service rate hearings.

10.1 Distribution Cost Allocation

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[149] Regulation Body of Knowledge 5. "Earnings Measurement." Retrieved 2016, October 14, from http://regulationbodyofknowledge.org/financial-analysis/earnings-measurement/.

[150] Alberta Utilities Commission (2012). "Rate Regulation Initiative: Distribution Performance-Based Regulation." from http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf.

Fortis' distribution costs can be separated into two major groups: 'distribution property subtotal' and 'other costs'. Distribution property subtotal includes vegetation management, depreciation, return on their rate base and operations. 'Other costs' include the cost of metering, billing, and load settlement for customers. Most of Fortis' costs are in the distribution property subtotal category (79.5%).

'Distribution property subtotal' costs are allocated based on the component analysis method (CAM). 'Other costs' are allocated based on a variety of cost allocation methods: billing costs are assigned per customer and load settlement costs are assigned per site.[151]

The CAM models Fortis' distribution network, and allocates costs to the different customer classes on the network. The CAM uses a sample of feeders on the distribution network and measures the electricity use of the customer classes using each feeder. The CAM allocates the distribution property cost of each feeder based on the average on-peak load of each customer class. The peak is measured at the transmission point of delivery.[152] Allocating costs based on a customer's use at peak hours is called a demand charge.

The cost of wires and transformers are correlated with peak demand on the network (CAM model). Distribution companies use the CAM model to allocate the cost of wires and

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[151] Alberta Utilities Commission (2014). "FortisAlberta Inc. 2012-2014 Phase II Distribution Tariff." from http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-018.pdf.

[152] Fortis Alberta Inc. (2010). "FortisAlberta Inc. 2010 Phase II ". Retrieved September 6th, 2016, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2010/2010-329.pdf.

transformers to customer classes. The cost of billing and load settlement are correlated with number of customers on the network. For this reason, the cost of billing and load settlement are allocated based on how many customers each customer class has.

The CAM model and the allocation of costs based on number of customers are methods of allocating costs when it is not clear who is responsible for incurring the cost. They split the cost based on some usage metric. Chapter 12 introduces economic theory on allocating costs based on marginal cost pricing.

The next chapter explains how the cost allocation methods of the DTS tariff and the CAM model are represented by the residential transmission and distribution tariffs.

Chapter 11 Current Residential Tariff Design in Transmission and Distribution Industries

Distribution costs are allocated between rate classes using the CAM model and a few other methods. Distribution rate classes include residential, commercial and industrial. The residential tariff then determines how costs allocated to residential customers are allocated between residential customers.

Transmission costs are allocated between transmission customers using the DTS tariff and then between distribution rate classes using a cost allocation process similar to the DTS tariff. The residential transmission charge then determines how transmission costs allocated to the residential rate class are allocated between residential customers.

The first step to determining the level of residential transmission and distribution charges is determining the costs that are allocated to residential customers. Chapter 9 and 10 provided the method of allocating transmission and distribution costs to residential customers. The second step is determining what percentage of those costs will be charged using a fixed, demand and energy charge. A fixed charged is charged monthly and does not change month to month. A demand charge is based on the rate at which electricity was consumed at peak times. An energy charge is based on the volume of electricity consumed.

In the case of residential customers, there is no way of measuring the rate of consumption at any given time because residential meters cannot measure this. Residential meters measure volume of electricity used.[153] For distribution, the cost allocated to residential customers is split between a fixed charge and an energy charge. The cost allocated to the fixed residential charge is then divided by the expected number of sites. This creates the charge per site on an annual basis. The cost allocated to the energy charge is divided by the expected energy use by residential customers. This creates the per kWh charge for distribution for residential customers.

For transmission, there is only an energy charge, so all transmission costs that are allocated to residential customers are allocated to the energy charge. The costs allocated to the energy charge is then divided by the expected energy use by residential customers. This creates the per kWh charge for residential customers.[154]

Since rates need to be set before the distribution/transmission cost and number/consumption of customers is known, it is necessary to forecast the cost, number of customers, and consumption of customers. The number of customers is forecasted using expected increases in the housing stock. The energy use is forecasted based on the expected energy use of residential customers.[155] The costs are forecasted based on what costs the utility expects to incur in that year.[156] Once the costs are forecasted they can be divided by the customer consumption or number of customers to determine the tariff.

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[153] The Alberta Utilities Commission (2011). "Alberta Smart Grid Inquiry ". Retrieved August 22, 2016, from http://www.energy.alberta.ca/electricity/pdfs/smartgrid.pdf.

[154] EPCOR Distribution & Transmission Inc. (2008). "2007-2009 Phase II Distribution Tariff Application." Retrieved February 12th, 2018.

[155] Ibid.

[156] Ibid.

The residential tariffs for FortisAlberta, Enmax, Epcor and ATCO Electric all follow the same structure. Transmission is charged based on volume of electricity consumed and distribution is charged based on volume of electricity consumed and a fixed monthly charge.[157] Charges based on volume of electricity consumed are called energy or variable charges. Charges based on electricity consumption at peak times are called demand charges. Charges that are not dependent on volume or peak electricity use are called fixed charges.

The tariff structures of FortisAlberta originates from its predecessor, Aquila Networks Canada. The history of Aquila and FortisAlberta explains why FortisAlberta's uses a variable charge for transmission and a fixed/variable charge for distribution. The history of Enmax, Epcor and ATCO Electric's tariffs are not covered in this paper. FortisAlberta's provides justifications for the tariff structure used by all four distribution companies. It is possible that Enmax, EPCOR and ATCO had different reasons for implementing the current tariff structures. Fortis provides one justification for the tariff structure currently in place.

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[157] Enmax (2016). "ENMAX POWER CORPORATION ("EPC") DISTRIBUTION TARIFF RATE SCHEDULE." Retrieved August 23rd, 2016, from https://www.enmax.com/ForYourHomeSite/Documents/2016-07-01-DT-Rate-Schedule.pdf.

FortisAlberta Inc. (2016). "FORTISALBERTA INC. 2016 ANNUAL RATES FILING RATES, OPTIONS, AND RIDERS SCHEDULES October 1, 2016." Retrieved October 6th 2016, from http://fortisalberta.com/docs/default-source/default-document-library/2016-oct-rates-options-riders-schedules.pdf?sfvrsn=6.

Epcor (2016). "DT – Schedule 1Distribution Access Service Tariff ". from http://www.epcor.com/power-natural-gas/Documents/DistributionAccessServiceTariff-2016-01.pdf.

ATCO Electric (2016). "ATCO Electric Price Schedule Index." Retrieved October 7th, 2016, from http://www.atcoelectric.com/Rates/tariffs/Documents/2016%20Tariffs/2016-01-01%20AE%20Price%20Schedules.pdf.

FortisAlberta's current tariffs originate from the period of electricity deregulation in Alberta. Deregulation occurred between 1996 and 2002. Prior to deregulation, three vertically integrated utilities, TransAlta Utilities, Alberta Power (ATCO), and Edmonton Power provided electricity to Albertans.[158] Vertical integration means that one company provides generation, distribution and transmission services to its customers.

As a result of deregulation, TransAlta unbundled its transmission, distribution and generation services. This resulted in separate tariffs and companies for transmission, distribution and generation. Distribution and transmission were both charged based on a fixed and an energy charge.[159]

In 2000, Aquila purchased TransAlta Utilities distribution network under its previous name, Utilicorp Networks Canada Alberta (UNCA).[160] In 2002, UNCA changed its name to Aquila Networks Canada.[161] We will refer to UNCA as Aquila. In 2004 FortisAlberta purchased Aquila.

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158 Andre Plourde; Stephen J. Rassenti; Vernon L. Smith; Bart J. Wilson;, T. J. B. T. J. C. T. D. D. E. D. J. D. M. G. W. W. H. L. L. K. C. S. P. (2007). Electric Choices: Deregulation and the Future of Electric Power. Lanham, Rowman & Littlefield Publishers.

159 Alberta Energy and Utilities Board (2000). "2000-12 - 1996 Electric Tariff Application Phase II - Second Refiling." Retrieved September 16th, 2016, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2000/2000-12.pdf.

160 Alberta Energy and Utilities Board (2001). "Issue of Common Equity." Retrieved January 30th, 2017, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2001/2001-47.pdf.

161 Aquila Networks Canada (Alberta) Ltd. (2003). "Decision 2003-019: Aquila Networks Canada (Alberta) Ltd. 2002/2003 Distribution Tarif." Retrieved September 23rd, 2016, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2003/2003-019.pdf.

Aquila inherited TransAlta's distribution and transmission tariff structure that was created after deregulation. TransAlta's tariff structure was a fixed and energy charge for transmission and a fixed and energy charge for distribution.

In 2001, Aquila filed a distribution tariff application with the regulator. Over the next two years this resulted in the transmission charge being changed to an energy charge, and the distribution charge continuing as a fixed/energy charge. The hearing discusses why Aquila continued to use TransAlta's fixed/energy distribution charge and it provides some insight into for why Aquila introduced an energy transmission charge.

11.1 Aquila's Distribution Tariff

Aquila continued to use a fixed/energy distribution charge because it represents the demand charge used to allocate distribution costs. A demand charge allocates costs based on a customer's electricity consumption at peak times.

The ratio between fixed and energy charges was set such that fixed charges collect 49% of the revenue requirement for residential customers. It is not specified why this ratio was used.[162]

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[162] Ibid.

A proxy for demand is necessary because residential meters cannot measure demand (electricity use at peak times). Residential meters measure the volume of electricity consumed over the period of a month, not the flow of electricity at peak times.[163] Measuring demand requires more advanced meters that are not used by residential customers in Alberta.

It is argued that an energy charge is a reasonable proxy for a demand charge because the volume of electricity a residential customer uses is positively correlated with the demand a residential customer uses at peak hours.[164] High volume customers typically consume relatively high amounts of electricity at peak times.

A fixed charge is argued to be a reasonable a proxy for a demand charge because a demand charge is usually stable. Residential customer's peak demand does not fluctuate significantly month-to-month and this is represented by a fixed monthly charge.[165] Aquila's fixed and energy charges were both attempts to represent demand charges without the ability to measure demand for residential customers.

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[163] The Alberta Utilities Commission (2011). "Alberta Smart Grid Inquiry ". Retrieved August 22, 2016, from http://www.energy.alberta.ca/electricity/pdfs/smartgrid.pdf.

[164] Alberta Utilities Commission (2014). "FortisAlberta Inc. 2012-2014 Phase II Distribution Tariff." from http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-018.pdf.

[165] Public Service Company of Colorado (2016). "Brockett Direct Testimony (Exhibit 103)." Retrieved October 12th, 2016, from https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=664415&p_session_id=.

11.2 Aquila's Transmission Tariff

The hearing does not explain why Aquila choose to introduce a variable transmission charge. Aquila only states that it designed its transmission tariffs to mirror the structure of the existing Transmission Administrator (TA) tariff. The TA tariff is the equivalent of today's DTS tariff. The TA tariff had charges based on demand and based on energy use.[166]

It is reasonable to assume that Aquila choose to adopt a variable charge for transmission because it was a reasonable proxy for the TA tariff's demand charge and it was the same cost allocation method as the TA tariff's energy charge.

Today, FortisAlberta still uses the variable transmission tariff and fixed/variable distribution tariff. Alberta's three other distribution companies also use the same tariff structure.

Alberta's residential tariffs are a result of attempting to mimic complex transmission and distribution cost allocation methods with simple volume-based residential meters. The demand, energy and fixed charges of the DTS tariff all get simplified to a variable transmission charge for residential customers. The CAM model used by distribution companies and the cost allocation methods for 'other costs', gets simplified to a fixed and variable charge.

[166] Aquila Networks Canada (Alberta) Ltd. (2003). "Decision 2003-019: Aquila Networks Canada (Alberta) Ltd. 2002/2003 Distribution Tarif." Retrieved September 23rd, 2016, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2003/2003-019.pdf.

It is difficult to justify why fixed and energy charges are used to mimic the demand charge used in transmission and distribution cost allocation. Both transmission and distribution use demand charges to allocate costs, yet transmission and distribution use different residential tariffs.

The following chapter provides an alternative to mimicking the cost allocation process using energy or fixed charges. Economic theory provides clearer arguments for the most efficient structure for residential transmission and distribution tariffs.

Chapter 12 Marginal Cost Pricing for Transmission and Distribution Industries

The current tariffs are set using a cost allocation process. If the current transmission and distribution tariffs in Alberta remain in place it is likely to incent between 2965MW and 5878 MW of rooftop solar by 2030.

Efficient solar adoption requires marginal cost transmission and distribution tariffs. Marginal cost pricing for electricity distribution creates tariffs that are very similar to the current cost allocation tariffs. Cost allocation and marginal cost pricing are completely different processes, but they create the same tariff structure (fixed and variable charge). Note that cost allocation and marginal cost pricing would not create the same level of fixed and variable charges (the price level would differ). Marginal cost pricing for transmission does not match the current cost allocation transmission tariffs.

12.1 Cost Categories

Marginal cost pricing requires a brief explanation of costs categories. Variable and capacity costs relate to the marginal cost of production. Fixed costs are not included in the marginal cost of production, but they are important to consider when designing tariffs. There are long-run and short-run fixed, variable, capacity and marginal costs.

A long-run cost means that you are considering a longer time horizon. There are no limits on the amount of time it would require to expand production. All aspects of production can be expanded and there are no costs that are considered sunk. Sunk costs are costs that cannot be avoided.

Short-run costs are costs faced by a firm with a shorter time horizon. There is no time to expand certain factors of production. This impacts costs by freezing the level of certain factors of production. Also some factors of production cannot be avoided and are sunk. Sunk costs are ignored by the firm because they cannot be avoided.

Variable short or long-run costs are those that increase when output increases. In the case of transmission and distribution, an example of a short-run variable cost is the cost of line losses. An example of a long-run variable cost would also be line losses as well as transformer size.

Fixed short or long run costs are those that do not change with output. Long run fixed costs are costs that do not change with output on a longer time horizon. Short-run fixed costs are costs that do not change with output on a shorter time horizon.

There are not very many examples of long-run fixed costs. Most costs associated with transmission and distribution increase as production increases. The land allocated to a transmission line is an example of a fixed cost because the amount of land does not change when a larger transmission line is installed.

The third category of costs is capacity cost. Capacity costs are in between variable and fixed costs. Capacity costs increase with output, but once they have been incurred, they are sunk in the short-run.[167]

Capacity costs are very relevant to transmission and distribution. As the volume of electricity used on the network increases, there are capital additions that are required to serve load. These are the capacity costs. Capacity costs are an important element of the long-run marginal cost.

The last category is marginal cost. This is the most important of all of the cost categories. Marginal cost is the cost of producing the last unit of output. There are long-run and short-run marginal costs. Short-run marginal costs do not include capacity costs. Short-run marginal costs would include the variable cost of the last unit of output. Capacity costs have already been invested and are sunk in the short run.[168] Line losses are an example of a short-run marginal cost in transmission and distribution.

Long-run marginal costs do include capacity costs. In transmission and distribution, this would mean that the cost of expanding the transmission network would be included in the marginal cost of transporting another MW of electricity.

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[167] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

[168] Ibid.

Long-run marginal costs create an efficient outcome in the long-run. An efficient long-run outcome is one that minimizes cost in the long run. When prices are set at long-run marginal costs it allows consumers to choose the lowest cost technology. It is important that residential electricity customers face prices that reflect long-run marginal cost because it incents them to choose production technologies that will minimize cost in the long-run. If solar panels have a lower overall cost compared to grid electricity in the long-run, then prices should incent customers to switch.

It is essential that Alberta's residential transmission, distribution, and electricity prices reflect the long-run marginal cost of transmission, distribution and generation.

12.2 Long-Run Marginal Cost of Transmission

Marginal cost pricing in transmission starts with the cost characteristics of transmission. Transmission costs are characterized by large investments in infrastructure alongside relatively small labour and maintenance costs.

Transmission costs in Alberta are the AESO's revenue requirement. Eighty one percent of the AESO's forecasted revenue requirement for 2017 is cost of 'wires'. The cost of wires is the revenue requirement of TFO's. The remaining nineteen percent of the AESO's revenue requirement are the AESO's administration costs, the cost of line losses and ancillary services. Nine percent of the AESO's costs are the cost of ancillary services.[169]

The cost of 'wires' is the revenue requirement of transmission companies, which includes administration and operating costs of the transmission companies. For example, ATCO Electric's transmission revenue requirement is composed of the cost of fuel, operating costs, depreciation, return on rate base and income taxes. 75% of ATCO Electric's revenue requirement is the cost of depreciation and the return on the rate base.[170]

Depreciation and the return on the rate base are the capacity cost of transmission. They are the cost of the physical assets that are necessary to transport electricity. If the proportion of capacity costs of ATCO Electric match the other transmission companies then this number can be used to further separate the AESO's cost of wires into capacity costs and administration and operating costs. This means that 61 % of the AESO's costs are the capacity cost of transmission.[171]

The remaining 39% of costs associated with transmission are the administration costs of the AESO and the TFO's, the cost of line losses and ancillary services of the AESO and the cost of fuel, and operating costs of the TFOs.

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[169] AESO (2016). "Alberta Electric System Operator 2017 ISO Tariff Update." Retrieved March 1st, 2017, from https://www.aeso.ca/assets/Uploads/AESO-2017-ISO-Tariff-Update-Application2.pdf.

Ancillary services are energy that is procured in the event of a supply shortfall on the electricity grid. Electricity needs to be supplied in real time, so it is essential to have backup energy in case some supply is lost.

[170] ATCO Electric (2016). "2015-2017 Transmission General Tariff Application." Retrieved March 1st, 2017, from http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2016/20272-D01-2016.pdf.

[171] 75 percent* 81 percent = 61 percent.

The long-run marginal cost includes all transmission costs. It is the incremental cost of transporting another unit of electricity on the transmission network. As customers consume more electricity from the grid, the level of capacity is expanded, line losses increase and administration and operating costs increase for the AESO and the TFOs.

The high percentage of capacity costs (61%) in transmission means that the long-run marginal cost of serving the first few MW or MWh of electricity on the transmission network are high. The bulk, regional and POD wires are all necessary to serve customers. As more customers are added to the network more POD connections are required, but the same network of regional and bulk wires can be continued to be used.

This means that the marginal cost of serving customers decreases as output is expanded on a transmission network. The initial cost is high, but additions require a lower cost. This attribute of transmission is crucial for tariff design.

12.3 Distribution Cost Characteristics

Distribution costs can be separated into 'operations and maintenance' costs and depreciated costs. Examples of distribution operating and maintenance costs are cost of labour, vegetation management, and load settlement.[172] Examples of depreciated distribution costs include the capital received for buildings, poles, towers and fixtures, overhead conductors, transformers and regulators, and digital meters.[173]

Depreciated distribution costs are the physical assets needed to deliver electricity to customers; they are the capacity costs associated with distribution. 30.5 percent of Fortis' rate base in 2012 was depreciation payments and 32 percent was the return on the rate base. This means that 62.5 percent of distribution costs are capacity costs or the interest paid to shareholders to borrow money to pay for the capacity costs.

The remaining 37.5% of distribution costs are the cost of operations, vegetation management, metering, billing, load settlement, and administrative costs.[174]

The long-run marginal cost is the incremental cost of the last unit of electricity produced on the distribution network. It includes all costs associated with distribution. An additional kWh or kW sold at peak times can require additional capacity, operations costs, vegetation management, metering, billing, load settlement and administrative costs.

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[172] Alberta Utilities Commission. "Decision 134 - 2011-2012 Phase I Distribution Tariff." Retrieved November 30th, 2015, from http://www.auc.ab.ca/applications/decisions/Decisions/2011/2011-134.pdf.

[173] FortisAlberta Inc. (2012). "Decision 2012-108." Retrieved October 14th, 2016, from http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-108.pdf.

[174] Alberta Utilities Commission (2014). "FortisAlberta Inc. 2012-2014 Phase II Distribution Tariff." from http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-018.pdf.

The size of a transformer is an example of a distribution cost that increases as consumption of electricity at peak times increase. If a customer increases their consumption of electricity at their peak electricity use, it can require a larger transformer.

Other capacity costs like poles and conductors are not impacted by the electricity used by a customer at peak times. Increased electricity use by customers can require a transformer upgrade, but the conductors and poles remain the same.[175]

Economic theory on tariffs is focused on marginal, or incremental cost. The first MW of electricity produced on the distribution network requires poles, conductors, transformers and the associated vegetation management and administration costs. As a customer consumes more incremental or marginal costs are incurred. The transformer may need to be upgraded to transport additional electricity on the network.

The initial cost of supplying the first few kW or kWh to a customer are very large. 62.5 percent of distribution costs are capacity costs and a portion of that capacity cost is poles and conductors that must be installed to supply electricity. Once the initial network is built, then additional costs like transformers are necessary to supply larger loads.

This concept of large initial costs and lower incremental costs is crucial to tariff design in distribution and transmission.

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[175] Ibid.

12.4 Natural Monopoly

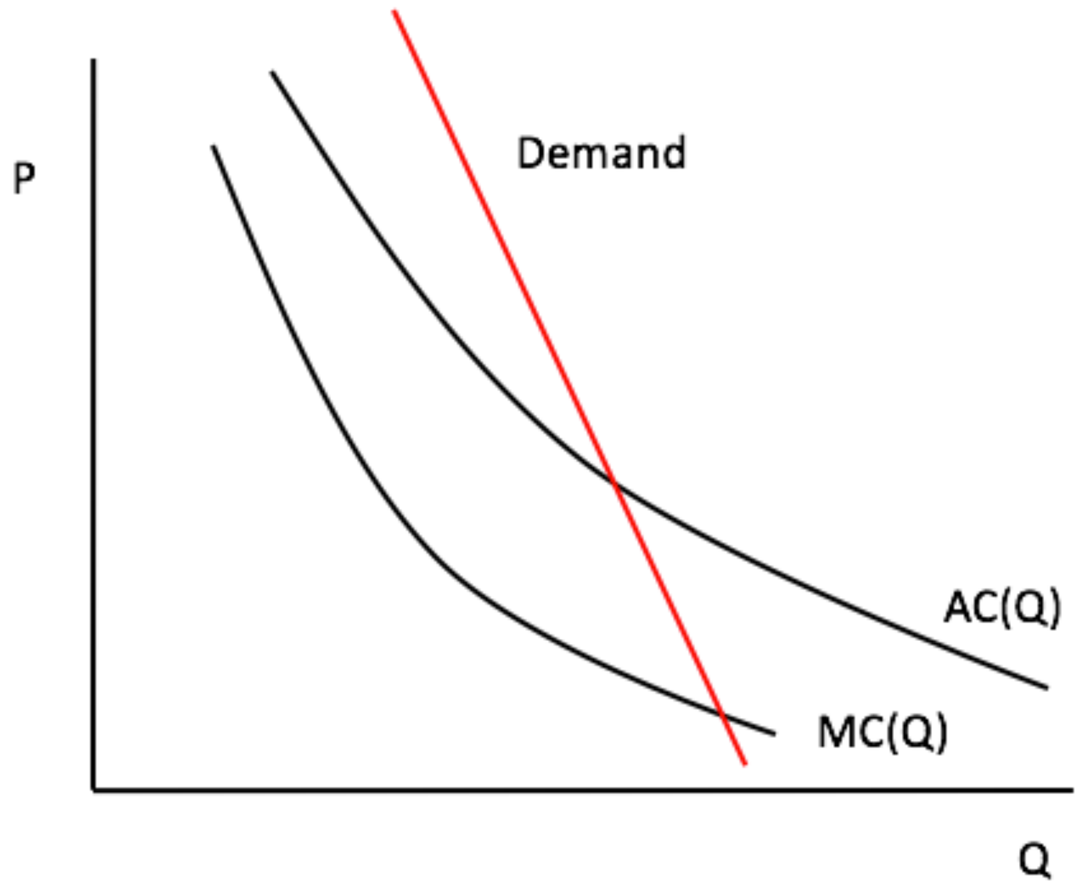
Transmission and distribution are examples of natural monopolies. Natural monopoly occurs when an industry's costs are subadditive. Subadditive costs means that the cost of producing a given level of output is smaller when one firm produces the output compared to when several firms produce the output.[176]

Some natural monopolies exhibit decreasing average costs. Decreasing average cost means the total cost divided by units decreases as units produced increases.[177] Transmission and distribution would be examples of industries that have decreasing average costs. An example of decreasing average costs is illustrated below.

[176] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

[177] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.Ibid.

Figure 15 - Natural Monopoly: Single Product Firm



178

There is a relationship between average costs and marginal costs. Average cost is total cost divided by total output. If average costs are decreasing it means that the marginal cost of the next unit is less than those units produced before. The decreasing cost of additional units brings down the average cost of the firm.

[178] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

Transmission and distribution experience decreasing average costs. The average cost of transporting the first few kW or kWh electricity on the distribution network is high because of the large investment necessary to build poles, conductors and transformers. The cost of additional kW or kWh of electricity is less because additional units only require smaller expansions to the system, like an increase in transformer size. It only requires a larger transformer to transport the additional electricity while previous units required poles, conductors and transformers to achieve the same outcome. Once the initial network has been built, the cost of transporting additional electricity decreases.

Given that distribution and transmission have decreasing average cost over all levels of output, it follows that marginal cost is below average cost. This is an important result for tariff design in the following section.

12.5 Tariff Design for Natural Monopolies

Economics evaluates tariff design in terms of whether "they provide appropriate price signals leading to efficient allocation of resources".[179] Efficient allocation of resources occurs when total surplus is maximized. The major methods employed by economics to create appropriate price signals for natural monopolies are Ramsey pricing, two part tariffs, and peak pricing.

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[179] Berg, S. V. and J. Tschirhart (1988). Natural monopoly regulation - principles and practice. Cambridge, Cambridge University Press.

12.5.1 Two-part tariffs and Ramsey pricing.

An issue that occurs when creating tariffs for natural monopolies is that marginal cost pricing does not create enough revenue to cover the costs of the firm. Given that marginal costs are less than average cost, if the price is set at the marginal cost of the last unit sold, it will be less that the average cost over all units of output. The firm cannot recuperate its costs because the price sits below the average cost of production.

Two part tariffs are a method of resolving this issue. Uniform two part tariffs charge a fixed fee for access to the service and a constant price for each unit consumed. Two part tariffs are favorable to economists because they allow a utility to charge marginal cost for the goods provided and recover remaining costs through the fixed fee.[180]

Ramsey prices can be applied to two part tariffs. Ramsey prices suggest adjusting the level of prices based on a consumer's elasticity. Ramsey two part tariffs adjust the size of the fixed fee to maximize surplus in the market. If the fixed fee is too high, some consumers may choose to not consume the good at all. Ramsey two part tariffs adjust the fixed fee based on the consumer's elasticity. Given that it increases surplus, Ramsey two part tariffs will lower a customer groups' fixed fee to include them in the market.[181] Ramsey prices would be applicable if there was a risk

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[180] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

[181] Berg, S. V. and J. Tschirhart (1988). Natural monopoly regulation - principles and practice. Cambridge, Cambridge University Press.

of solar customers disconnecting. See section 8.1 for why disconnection is unlikely for solar customers.

A two-part tariff for residential transmission customers would include an energy charge covering the long-run marginal cost of transmission and a fixed charge to cover the remaining costs of transmission.

A two-part tariff for residential distribution customers would include an energy charge covering the long-run marginal cost of distribution and a fixed charge to cover the remaining costs of distribution.

12.5.2 Peak pricing

There is one more layer of complexity necessary to create efficient tariffs for transmission and distribution. Two part tariffs collect long-run marginal cost based on output, regardless of when the output is consumed. In an industry like electricity, the time that electricity is consumed during the day and the year impacts the marginal cost of transmission and distribution.

Peak pricing provides a method of pricing a good when the time of consumption impacts marginal cost. There are three conditions for peak pricing. The first is that the good is produced over several time periods, and demand fluctuates in a predictable manner over those time periods. The second is that the firm's capacity must be the same over all time periods. The third is that the firm's output is not storable.[182]

Distribution and transmission exhibit these three attributes. Distribution and transmission experience a peak level of load over the year. There are daily peaks that occur in the morning as people get ready to go to work and in the evening as people come home from work. The time of day or the time of year when peaks occur is somewhat predictable. The level of capacity cannot be adjusted over the course of the year in distribution or transmission. Also, electricity storage is not currently economical on a large scale.

Peak pricing answers two questions regarding capacity in transmission and distribution: what is the efficient level of capacity and how should it be priced?[183]

A simplified peak pricing model considers two periods of equal length (on peak and off peak). Demand in the on peak period is high, and demand in the off peak period is low. The cost of capacity is (ß) for each period. This means that for off-peak and on-peak together the cost of capacity is (2ß). The variable cost is (b) for each unit of output.

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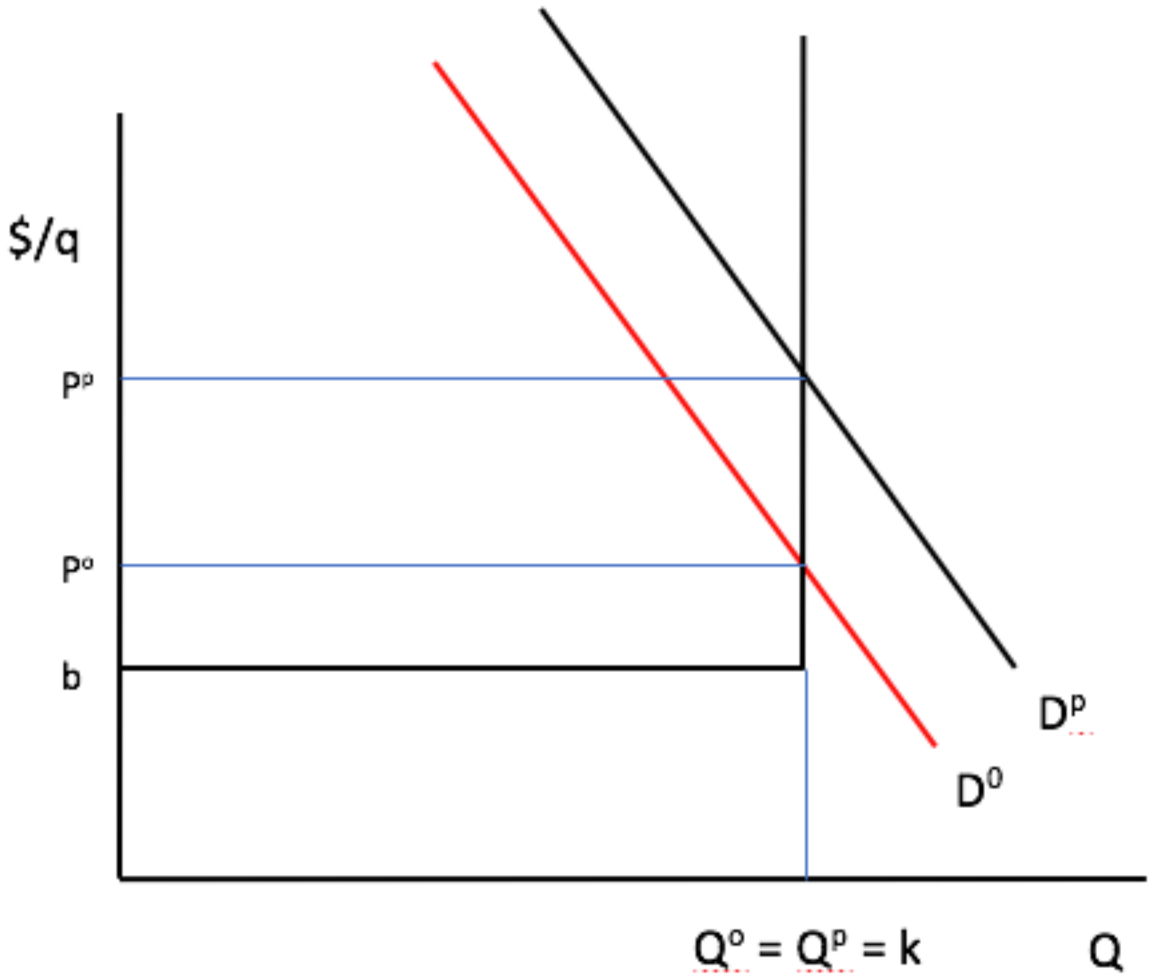
[182] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

[183] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

The level of capacity determines the maximum production of the firm and the price in each period. The level of capacity is ‘k’. The price in each period is set where the level of capacity intersects demand. If capacity is low (Figure 16), then the price will be high in both periods, because the small quantity produced increases the price (P^o and P^p). P^o is off-peak and P^P is on-peak.

Figure 16 - Efficient Rationing



[184]

If capacity is high, the price will be low in both period because the large quantity produced drives down the price. In the example of this scenario shown in Figure 17, the price sits at variable costs of production and capacity costs are not recovered.

Figure 17 - Efficient Pricing and Excess Capacity

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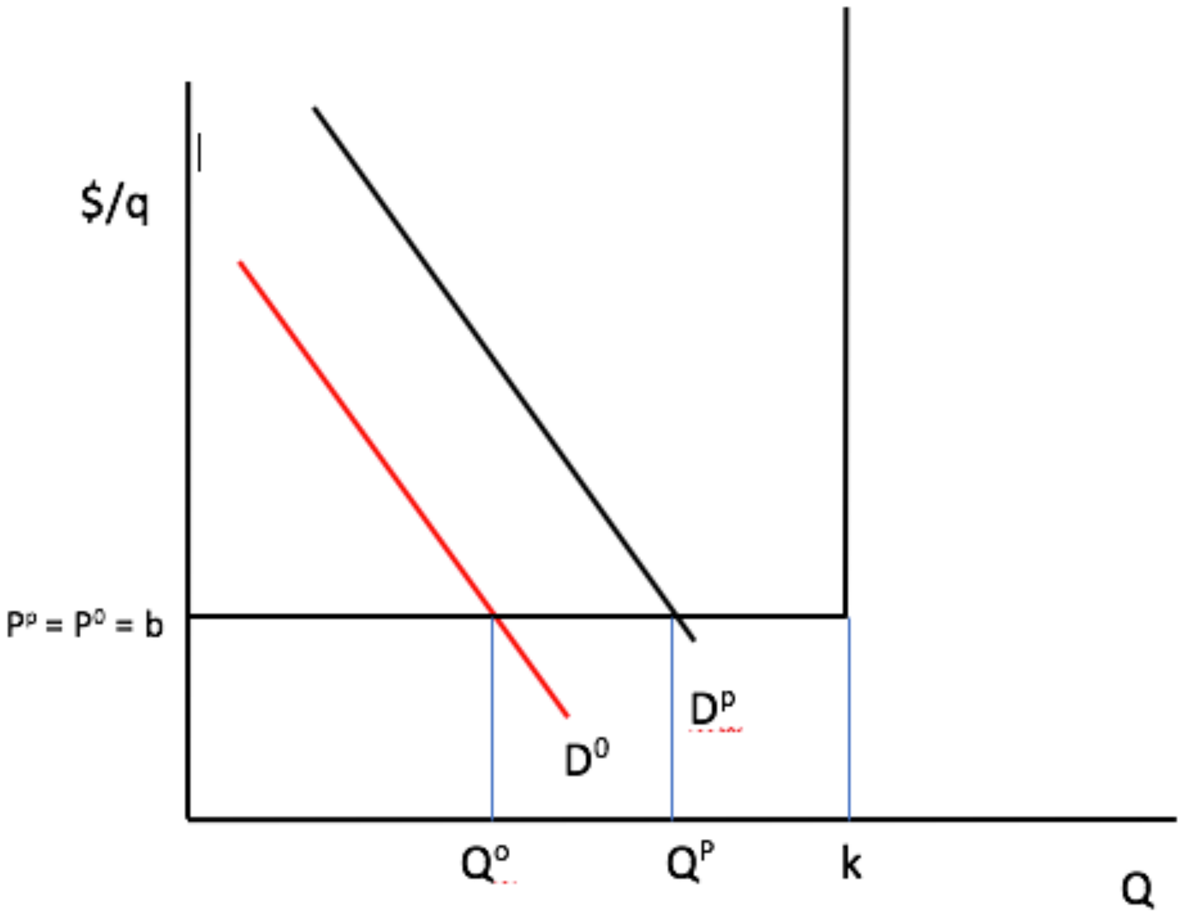
[184] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.



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In the long-run, the efficient price of the good allows the firm to just break even. The price in the off peak and on peak periods must just cover the long-run marginal cost of production (capacity plus variable cost) of serving both periods. This is b*output + (2ß).

The price paid in off-peak and on-peak changes based on the level of capacity. Figure 16 shows a high price due to low capacity and Figure 17 shows a low price due to high capacity. The

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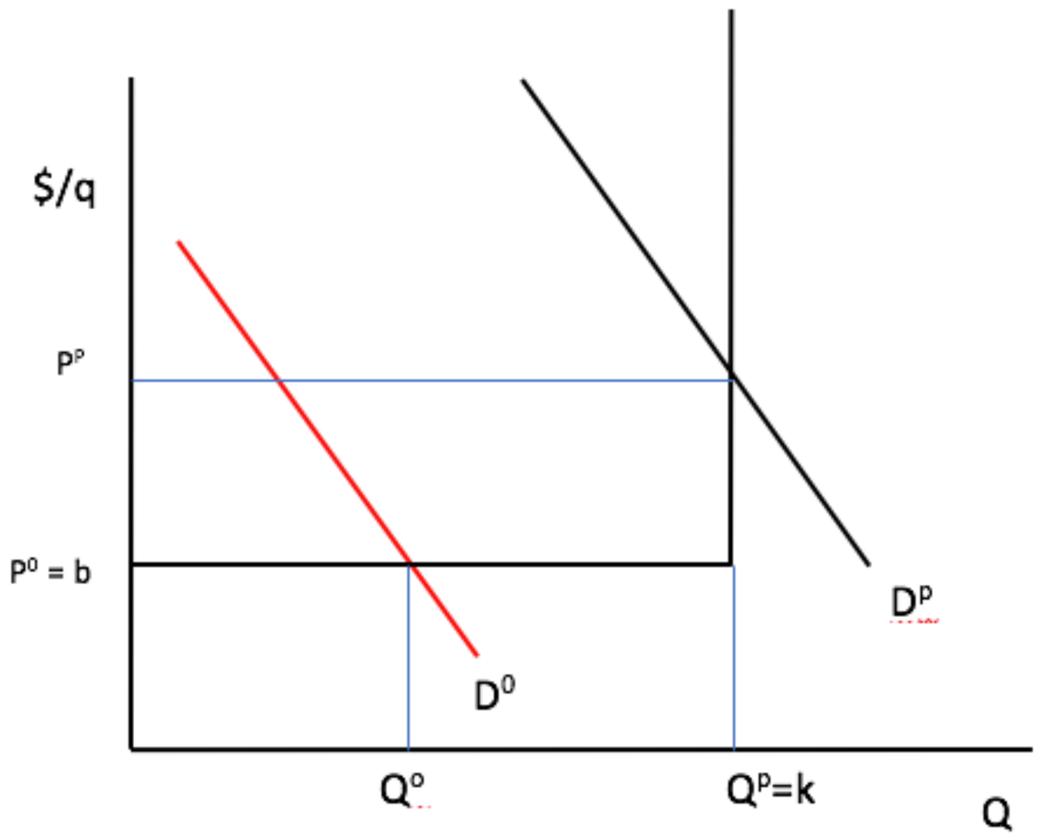
[185] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

efficient level of capacity is the capacity that leads to a price that creates enough markup above variable cost (b) in each period to just cover the cost of capacity in both periods (2ß).

Depending on the difference in demand between the on-peak and off-peak periods, the share of capacity costs that is allocated between the on-peak and off-peak period changes. If the difference in demand between peak and off-peak periods is large relative to the cost of capacity, then the on-peak period will pay the entire capacity cost. In Figure 18 the demand in the on-peak period (D^p) is much higher than the demand in the off peak period (D^o). This leads to the on-peak period paying the capacity cost for both periods.

Figure 18 - Excess Capacity Off-Peak and Rationing On-Peak



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If the difference in demand between the two periods is small relative to the cost of capacity, then the on-peak and off-peak will share the cost of capacity (see Figure 16).[187]

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[186] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

[187] Church, J. and R. Ware (2000). Industrial Organization: A Strategic Approach, The McGraw-Hill Companies, Inc.

This peak pricing model assumes constant returns to scale. Regardless of how much capacity is used in the peak period, the cost of capacity is flat, at Beta. If the model had increasing returns to scale, the Beta would fall as more capacity was built. Increasing returns to scale is an important characteristic of transmission and distribution. This version of the peak pricing model does not include this attribute.

The revenue acquired from off peak and on-peak must cover the variable costs and the cost of capacity of serving both periods. Consumption during the on-peak contributes a greater portion of capacity costs compared to consumption in the off-peak. This occurs because consumption during the on-peak has a higher willingness to pay as compared to consumption in the off-peak.

The major take away from peak pricing is the price in the on-peak period is higher than the price in the off-peak period. This attribute of peak pricing can be merged with two-part tariffs to create an efficient tariff for residential distribution and transmission customers.

12.6 Applying Peak Pricing and Two-Part Tariffs to Residential Tariff Design

Two-part tariffs provide a tariff design that can be implemented in industries that are natural monopolies. Marginal cost pricing communicates the cost of providing the last MW or MWh of electricity and a fixed charge covers the remaining costs associated with providing the service.

Peak pricing adds an additional layer. It considers what happens when marginal cost changes based on the time of day. Consumption in peak periods has a higher price and consumers in the peak period pay a larger portion of capacity costs.

Transmission and distribution can implement both ideas using an energy charge for electricity consumed and a fixed charge to cover the remaining costs associated with transmission or distribution.

Peak pricing taught us that the optimal prices change based on the time of day. The marginal cost of consumption is high in the peak period and low in the off-peak period. A common method of charging on-peak consumption a higher price than the off-peak in the electricity sector is using demand charges. Demand charges are based on consumption at peak times. The CAM model and the demand charge in the DTS tariff are examples of demand charges.

In the residential sector, the demand charge would need to be approximated using an energy charge. Residential meters cannot measure demand; they only measure volume of electricity. Fortis explained that an energy charge is a reasonable proxy for a demand charge. Those who consume a lot at peak times typically also consume a large volume of electricity. [188]

The energy charge would be set to approximate the demand charge. It would be possible to set the energy charge to a level such that the total revenue collected under the energy charge is about

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[188] See Section 11.1

the same as what would have been collected under a demand charge. An energy charge set at marginal cost and a fixed charge to cover the remaining cost is the most efficient residential tariff design for both transmission and distribution.

Ramsey prices are useful when there is a risk of the customer disconnecting from the service. Ramsey prices consider a customer’s ability and willingness to disconnect from the grid and total surplus is maximized based on this response. The paper assumes that customers are not likely to disconnect and therefore Ramsey prices are not necessary. The storage section argued that solar customers are not currently able to and are not likely to be able to disconnect from the grid in the future. As solar costs decrease, the incentive to install solar will rise but the incentive/ability to disconnect is less likely to be a factor. Ramsey prices are useful when there is a risk of customers disconnecting. In the case of residential customers, disconnection is unlikely.

Although residential customers are not likely to disconnect, they will respond to variable distribution and transmission charges by installing rooftop solar. A tariff that more accurately communicates the long-run marginal costs of transmission and distribution would avoid residential customers substituting to solar too early.

The current distribution tariff created by cost allocation matches the structure of a marginal cost tariff. A fixed and a variable charge includes the two-part tariff’s decreasing marginal cost and peak-pricing’s ability to charge peak consumption a higher price.

The current transmission charge for residential customers does not match the marginal cost tariff. The current transmission tariff is a variable charge. A variable charge without a fixed charge communicates that marginal costs sits at or above the average cost of production. This is not an accurate representation of the marginal cost of transmission.

The variable transmission charge leads to residential customers adopting solar too early. The variable transmission charge overstates the marginal cost of transmission. Customers install solar in response to the savings in transmission from the variable charge. If the transmission tariff incorporated a fixed charge alongside the variable charge, it would communicate the savings associated with consuming less electricity from the grid.

The marginal cost tariffs for transmission show that 5878 MW by 2030 is not an efficient amount of rooftop solar. 5878 MW is too high. Customers are not responding to marginal cost pricing. If the transmission tariff reflected the marginal cost of transmission then customers would have a smaller incentive to install solar. Chapter 14 and 15 review studies from other jurisdictions on the long-run marginal cost of transmission and distribution. These studies are applied to Alberta to determine the efficient level of rooftop solar adoption for Alberta.

Chapter 13 Efficient Electricity Price

Transmission and distribution are not the only price signals that residential customers respond to when considering solar installations. The price of electricity is also an important price that impacts the efficiency of the rooftop solar market. If the price of electricity is set at the marginal cost of producing electricity from the grid, then rooftop solar customers will be incented to install rooftop solar in an efficient manner. If the price of electricity is higher or lower than the marginal cost of electricity, then rooftop solar will not receive the correct incentive to install rooftop solar.

In Alberta solar customers receive a credit for the electricity they put back onto the grid. The credit they receive is set at the same rate that they pay for electricity from their electricity retailer (retail rate of electricity). Residential customers have access to a regulated electricity rate and competitive contracts.

The regulated power rate is called the Regulated Rate Option (RRO) and it is based on pool prices. [189] Every month a new RRO is calculated for each retailer that offers the RRO. The RRO for a given month is calculated using a load forecast and the forward electricity prices.[190] The RRO includes a risk margin. The risk margin covers the retailer for volume risk, price risk, credit

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[189] Alberta Utilities Commission. "Alberta’s energy market." Retrieved September 28, 2016, from http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx.

[190] Government of Alberta. "ELECTRIC UTILITIES ACT REGULATED RATE OPTION REGULATION." Retrieved September 28th, 2016, from http://www.qp.alberta.ca/documents/Regs/2005_262.pdf.

risk and unaccounted for energy and losses. [191] The retailers receive a margin to cover risk because they are providing a service to residential customers. Retailers purchase wholesale electricity from the market at commit to selling residential customers electricity at a predetermined rate. The risk associated with reselling wholesale electricity to residential customers is accounted for in the risk margin. On top of the risk margin, the RRO includes a reasonable rate of return to the retailer for providing electricity services.[192] This is to cover the opportunity cost of participating in the retail electricity market.

The current structure of RRO tariffs in Alberta are a per KWh charge for energy used and a monthly charge or daily charge for administration costs.[193] Alberta's residential customers can also sign a contract to receive electricity from a competitive retailer. The competitive contracts are similar to the RRO in that retailers will purchase electricity from the power pool and sell it to residential customers with an added premium for risk and a rate of return for the retailer.[194]

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[191] Ibid.

[192] Ibid.

[193] Direct Energy Regulated Services (2016). "Our Current Regulated Rate Tariff (RRT)." Retrieved September 29th, 2016, from http://www.directenergyregulatedservices.com/ELE/Electricity-Rates.aspx.

EPCOR (2016). "REGULATED ELECTRICITY RATES & CHARGES." Retrieved September 29th, 2016, from http://www.epcor.com/power-natural-gas/regulated-rate-option/Pages/residential-rates.aspx.

ENMAX (2016). "Regulated Rate Option." Retrieved September 29th, 2016, from https://www.enmax.com/home/electricity-and-natural-gas/tariffs/rro.

[194] Alberta Utilities Commission. "Electricity." Retrieved September 29th, 2016, from http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Pages/Electricity.aspx.

Reimbursing residential rooftop solar customers with the retail rate of power is problematic because it results in double counting of costs. When the retailer sells electricity to a residential customer, the retail price includes the risk margin and a rate of return for the retailer. These costs are born by the retailer and the retail rate is meant to reimburses the retailer for these costs. When a residential customer produces more electricity than they consume they sell the electricity back to the retailer at the retail rate of electricity. The risk margin and the rate of return are accounted for again and passed on to the residential solar customer.

Including the risk margin and the rate of return in the reimbursement price for solar results in the retailer subsidizing solar. The cost of the risk margin and the rate of return is double counted and this results in the retailer passing on revenue that could have covered these costs onto the residential solar customer.

If residential customers were reimbursed for excess solar production using the wholesale price of electricity, the double counting of the retailer's costs would not occur. The retailer would recover the risk margin and the rate of return from customers that it sold electricity to. Rooftop solar customers would recover the cost of producing electricity with the wholesale price of electricity. The wholesale price of electricity covers the cost of producing electricity for residential customers and the retail rate covers the costs associated with selling electricity to residential customer for electricity retailers. This avoids double counting the costs associated with providing retail electricity services.

Assuming that Alberta's wholesale electricity market is competitive, the pool price reflects the long-run marginal cost of producing electricity. It provides the correct price signal for the excess residential solar production. Residential customer can compete with other generators in the province by producing electricity for consumption on the grid.

Once the capacity market is implemented in Alberta, the pool price will no longer represent the long-run marginal cost of generation. In the capacity market, generators will be reimbursed for generation costs through the pool price and a capacity market. The paper accounts for this change in the market by using the average energy cost (see Figure 1). The average energy cost includes both the pool price and the capacity payment in the years that the capacity market is implemented.

The price residential solar customers receive for the electricity they sell back onto the grid is likely to be too high because it includes a rate of return and a risk margin on top of the wholesale price of electricity. This incents residential customers to substitute to solar before it is efficient for them to do so. The incorrect reimbursement price for electricity supports that 5878 MW by 2030 is an inefficient amount of rooftop solar. If the price residential customers received was set at the average energy cost, then they would receive the marginal cost of electricity for excess electricity production. This would provide an accurate price signal and ensure that rooftop solar customers compete with other generators under the same price.

Incorrect price signals from transmission, distribution, and electricity leads to over installation of rooftop solar. Transmission and distribution tariffs need to be set at the long-run marginal cost of those industries. Since the marginal cost of transmission is decreasing, it follows that the current variable charge for transmission is too high. The next chapter uses studies from other jurisdictions to determine what the long-run marginal cost of transmission and distribution is. This is applied to Alberta to calculate the efficient level of rooftop solar and the inefficiency associated with Alberta's current transmission and distribution tariffs.

Chapter 14 Incremental Cost Savings from Rooftop Solar

The purpose of setting the energy charge for transmission and distribution at the long-run marginal cost of those industries is to properly communicate the costs of using the network. A rooftop solar customer should be able to look at the energy charge for distribution and transmission and decide if the savings from installing rooftop solar justify the costs.

There are studies that quantify the transmission and distribution cost savings that are created as a result of residential customers installing rooftop solar panels. This chapter uses these studies to estimate the savings that rooftop solar creates on Alberta's distribution and transmission networks. If the transmission and distribution tariffs are set up properly in Alberta, they should communicate the cost savings created by rooftop solar. This chapter compares the cost savings calculated in other jurisdictions to Alberta's energy charge for distribution and transmission. This provides additional evidence for why Alberta's transmission charge needs to be updated and why Alberta's distribution charge is correctly designed.

14.1 Xcel Energy's Study on Rooftop Solar's Impact on Transmission and Distribution Costs

In 2013, Xcel Energy Services published a cost benefit analysis of distributed solar generation (DSG). Colorado has a regulated electricity system. Xcel Energy Public Service Company of Colorado and Black Hills Energy provide electricity services in Colorado.[195]

Xcel Energy considered the impact of the first 59 MW of rooftop solar installed in Colorado as well as the impact of an additional 81 MW that was forecasted to be installed in 2014. In total, 140 MW represented 0.9% of Colorado's generating capacity in 2014.[196]

Xcel energy estimated that the incremental distribution cost savings provided by rooftop solar is $5.08/MWh (CDN), or 0.508 cents per kWh (CDN).[197] Distribution tariffs in Alberta range between 0.9 and 7 cents per kWh, depending on the DFO. Using Xcel Energy's estimate, a

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[195] Colorado Department of Regulatory Agencies. "Electric and Natural Gas Company Information." Retrieved August 26, 2016, from https://www.colorado.gov/pacific/dora/electric-and-natural-gas-company-information.

[196] US Energy Information Agency (2014). "Table 4. Electric power industry capability by primary energy source, 1990 through 2014." Retrieved October 13, 2016, from https://www.eia.gov/electricity/state/colorado/xls/sept04co.xls.

[197] US$3.6/MWh * 1.329 CDN$/US$ * (1.02)^(3)= $5.08

$3.6/MWh is the estimate provided by Xcel energy of the distribution savings created by rooftop solar. See Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

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1.329 is the Canadian/US exchange rate in 2016. See Internal Revenue Agency (2016). "Yearly Average Currency Exchange Rates
Translating foreign currency into U.S. dollars." Retrieved November 29th, 2016, from https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates.

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(1.02)^3 is increasing the 2014 value to 2017 dollars.

household that produces 600 kWh per month of solar energy in Colorado would provide $3.05 CDN of monthly distribution savings.[198]

Xcel Energy's cost saving calculation tells us what distribution costs are avoided when a solar customer produces electricity from their solar panel. It is the savings created on the distribution network from rooftop solar production spread over all hours of solar production. The savings come from the fact that electricity produced on a solar panel offsets the total amount of electricity that needs to be transported on the distribution network. Less electricity being transported on the distribution network means potential cost savings for the distribution company.

As discussed earlier, the marginal cost of distribution is the incremental cost of using electricity distribution. When a customer consumes an additional kWh of electricity from the network, the incremental cost of that kWh is the marginal cost. Xcel energy looks at it from the opposite direction. Xcel Energy asks, what is the incremental savings in cost of one less kWh of electricity on the network? The reduction of one kWh on the grid is the result of solar

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[198] ($3.6/MWh * 0.6 MWh * 1.329 $CDN/$US * (1.02)^3 = $3.05

$3.6/MWh is the base case distribution savings from Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

0.6 MWh monthly consumption of electricity is 600 KWh in MWh

1.329 $CDN/$US is the exchange rate. See Internal Revenue Agency (2016). "Yearly Average Currency Exchange Rates
Translating foreign currency into U.S. dollars." Retrieved November 29th, 2016, from https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates.
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production. Incremental cost savings and incremental costs are both marginal costs. They are just moving in opposite directions.

Xcel Energy's distribution cost savings calculation considered avoided distribution system capital costs, avoided distribution line losses, and voltage support costs. Avoided distribution system capital costs and voltage support costs are examples of capacity costs. Line losses are a variable cost.

Xcel Energy's is estimating the long-run marginal cost of distribution. Capital costs and voltage support costs are examples of costs that change in the long-run based on the volume of electricity consumed. Line losses are also included in the long-run marginal cost of distribution. There are also other costs associated with distribution that should also be included in the long-run marginal cost of distribution (vegetation management, and administration costs). Xcel energy provides a conservative estimate of the long-run marginal cost of distribution.

The 140 MW of solar distributed generation did not avoid any distribution capital costs for Xcel Energy.[199] There was no impact on voltage support costs for feeders that served residential customers.[200] The savings calculated by Xcel Energy came from distribution line losses. A second study from California calculates the impact of voltage support and capital costs. These

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[199] Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

[200] Ibid.

estimates are added to Xcel Energy's study to create an estimate of the long-run marginal cost of rooftop solar.

14.2 Californian Study on the Impact of Rooftop Solar on Distribution Costs

M.A. Cohen, P.A. Kauzmann, D.S. Callaway provide an estimate of the avoided distribution system capital costs that result from high levels of rooftop solar. The study uses data on distribution costs in California, and it runs simulations of different levels of Photovoltaic (PV) penetration.[201]

Higher PV penetration creates small decreases in distribution capital costs. The levelized avoided cost of distribution ranged between 0.05 to 0.21 US cents/kWh of rooftop solar production. Levelized avoided cost of distribution is very similar to the levelized cost of electricity. It is the avoided distribution capital costs amortized over the production of the solar panel over the entire life of the solar panel. It is the cost savings per kWh of solar production. Cost savings from solar production may occur over a specific hour in the day. The levelized avoided cost of distribution spreads those cost savings over all hours of solar production.

0.21 US cents/kWh is 0.28 CDN cents/kWh. Cohen et al. estimate is in 2012 dollars. 0.28 cents /kWh converted to 2017 dollars is 0.31 cents / kWh.[202] The study did not quantify the impact on distribution losses.

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[201] Photovoltaic refers to a the most common solar technology installed on residential households.
[202] (1.329 $CDN/$US) * ($0.0021USD / kWh) * (1.02)^5 = $0.0031 CDN/kWh

The reduction in distribution costs is a result of solar panels reducing the peak load that customers consume off the network. If the solar panel is producing electricity during the peak hour, then the customer's peak load decreases. Decreases in peak load can defer investments in transformer banks and conductors.[203]

Cohen et el. concludes that the impact of capital deferrals in distribution are very small even with high penetration levels.[204] Solar panels do not decrease peak load sufficiently to offset a significant amount of distribution capacity costs.

Cohen et al.'s study provides an estimate of the capacity cost savings created by rooftop solar. Xcel energy's study only found savings associated with line losses. Adding Cohen et al and Xcel energy's estimates together creates an estimate of losses and distribution capital deferral savings

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The exchange rate is taken from Internal Revenue Agency (2016). "Yearly Average Currency Exchange Rates Translating foreign currency into U.S. dollars." Retrieved November 29th, 2016, from https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates.

The distribution cost estimate is taken from Cohen, M. A., et al. "Effects of distributed PV generation on California's distribution
system, part 2: Economic analysis."

The value is inflated to 2017 dollars. Cohen, Kauzmann and Callaway's estimate is in $2012. Ibid.

[203] Cohen, M. A., et al. "Effects of distributed PV generation on California's distribution system, part 2: Economic analysis."

[204] Ibid.

created by solar customers. By adding the results of the two studies together, solar customers create 0.81 cents per kWh in distribution cost savings.[205]

0.81 cents per kWh approximates the long-run marginal cost of distribution in Colorado and California. 0.81 cents per kWh can be applied to the distribution tariffs in place in Alberta.

14.3 Cost of Transmission

Xcel energy did a study on avoided transmission costs resulting from rooftop solar installations. Xcel Energy estimated the transmission investments that a small level of DSG avoids as well as the transmission line losses that are avoided as a result of rooftop solar being located where the load is located.

The avoided transmission investments included in Xcel Energy's study are the interconnection costs for generation that is not required due to the production of the solar panels, and the deferral of distribution substation investments.[206] Less generation is needed as a result of solar panels producing electricity, and the study considers the transmission savings from generation being avoided.

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[205] 0.5 cents /kWh + 0.31 cents / kWh = 0.81 cents / kWh
[206] Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

Most of the transmission savings quantified by Xcel Energy come from the avoided interconnection costs for generation that is not built because of solar production.[207] During the time of the study (2014), Colorado's grid had 14,933MW of generating capacity. This is similar to Alberta's current 16261MW of capacity.[208]

Xcel estimated that rooftop solar creates $4.51CDN of distribution cost savings per MWh of solar production[209] or 0.45 cents /kWh. As a reference, Alberta's energy charges for transmission are between 2 and 4 cents per kWh.[210] A solar customer that produces 600 kWh's per month would provide $2.71 CDN of transmission savings per month.[211]

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207 Ibid.

208 Alberta Energy. "Electricity Statistics." Retrieved November 4th, 2016, from http://www.energy.alberta.ca/electricity/682.asp.

209 ($3.2 US/MWh) *(1.329 $CDN/$US) *(1.02)^3=4.51

The transmission cost estimate was taken from Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

The exchange rate was taken from Internal Revenue Agency (2016). "Yearly Average Currency Exchange Rates Translating foreign currency into U.S. dollars." Retrieved November 29th, 2016, from https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates.

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210 See table 1 in Chapter 5

211 ($3.2 US/MWh) *(0.6 MWh monthly consumption of electricity)*(1.329 $CDN/$US) *(1.02)^3= $2.71 CDN/month.

The transmission cost estimate was taken from Xcel Energy Services, I. (2013). "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Retrieved July 11th, 2016.

The exchange rate was taken from Internal Revenue Agency (2016). "Yearly Average Currency Exchange Rates Translating foreign currency into U.S. dollars." Retrieved November 29th, 2016, from https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates.

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Chapter 15 Applying Incremental Cost Studies to Alberta

The results of the studies from Colorado and California are specific to those regions. Alberta has its own characteristics that would change the cost impact of rooftop solar on transmission and distribution. Despite the differences between Alberta and Colorado/California, the results from Colorado and California are used as an approximation of the incremental cost savings of rooftop solar in Alberta. The incremental cost savings can then be used as an approximation of the long-run marginal cost of distribution and transmission.

15.1 Application to Alberta's Distribution and Transmission Networks

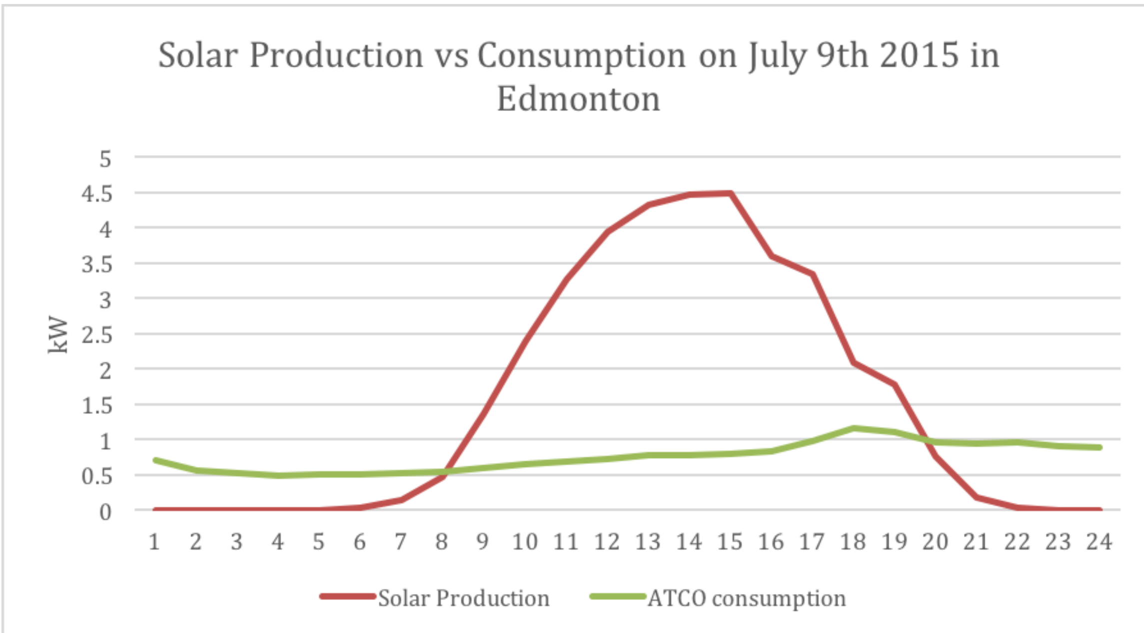
Cohen identified that distribution cost savings are driven by solar's ability to decrease net consumption during peak usage hours. Rooftop solar in Alberta is very effective at reducing peak electricity demand in the summer months and very ineffective in the winter months.

Daily residential consumption in Alberta peaks at 17:00 or 18:00 hours.[212] This coincides with residential customers coming home from work and turning on their lights and cooking dinner. On an annual basis residential consumption can peak in the summer or the winter.

[212] ATCO Electric. "Sample Profiling Data & Information." Retrieved November 17th, 2016, from http://www.atcoelectric.com/Services/retailers/Sample-Profiling-Data-and-Information.

Solar production at 17:00 or 18:00 hours is high enough in the summer to cover all electricity use. Below is a graph showing solar production and electricity use of the average ATCO customer on July 9th 2015. July 9th was the day with the highest electricity use in Alberta measured between May and October of 2015.

Figure 19 - Solar Production vs Consumption on July 9th 2015 in Edmonton



[213]

The graph uses a 5.75 kW system. This is composed of 25 solar panels and it produces enough electricity to cover electricity use of the average Alberta customer over the course of one year.

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[213] ATCO consumption sourced from ibid.

and solar production sourced from NAIT Alternative Energy Program (2015). " NAIT Reference Array Report March 31, 2015 (revB)." from https://solaralberta.ca/sites/default/files/NAIT%20Reference%20Array%20Report%20March%2031%2C%202015%20%28revB%29.pdf.

If a distribution network is summer peaking, a large enough solar panel can completely cover electricity use of a residential customer at peak times. Winter has the opposite outcome. In 2015, AIL peaked on January 5th between 17:00 and 18:00 hours. Solar production at that time was zero across the province, because the sunset occurs well before that time in January.[214]

Areas in Southern Alberta are summer peaking, due the increased air conditioning. Areas in northern Alberta are winter peaking due to a larger industrial base.

California is a summer peaking jurisdiction. Given that many distribution networks in Alberta are winter peaking, the distribution savings associated with rooftop solar in Alberta are likely to be less than what was estimated in California. Alberta's solar panels have a zero ability to reduce their consumption on peak in the winter months and this means the capacity cost savings on the distribution network are likely zero for winter peaking distribution areas. Cohen's estimate is used as a high estimate of the distribution savings associated with rooftop solar in Alberta.

Xcel Energy identified line losses and avoided generation connections as areas of cost savings on the transmission network. The paper applies this estimate of transmission costs savings to Alberta. Colorado is a summer peaking jurisdiction.[215] Solar is able to reduce transmission needs

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[214] The Old Farmer's Almanac. "SUNRISE & SUNSET FOR SWEET GRASS, MT." Retrieved July 6th, 2017, from http://www.almanac.com/astronomy/rise/zipcode/59484/2015-01-05.

Sweet Grass is a town on the border between Alberta and Montana. Sunset in Sweet Grass occurs at 16:46 on January 5th. All locations in Alberta are north of Sweet Grass and would have an equal or earlier sunset on that day.

[215] Energy Information Agency. "Colorado Electricity Profile 2016." Retrieved April 24th, 2018, from https://www.eia.gov/electricity/state/colorado/index.php.

in the summer time in Colorado when solar production is high. Alberta is a winter peaking jurisdiction and solar would have a lower ability to reduce transmission costs during that period. Colorado's estimate of transmission costs is used as a high estimate of the transmission savings associated with rooftop solar in Alberta.

15.2 Calculating the Inefficiency of Rooftop Solar in Alberta

ATCO Electric and Fortis' energy charges for distribution are much higher than the incremental savings estimated by Cohen and Xcel energy (0.81 cents/kWh). One possible reason that Fortis and ATCO's transmission and distribution charges are greater than the cost estimates from Colorado and California is that a large proportion of ATCO and Fortis customers are rural. ATCO and Fortis operate outside the two major cities in Alberta (Calgary and Edmonton). The long distances that must be covered to serve rural customers would increase the marginal cost of serving those customers. This is one likely reason why Fortis and ATCO's distribution charge is above the estimates calculated in the Colorado and California studies.

The California and Colorado studies do not specifically calculate a rural long-run marginal cost of transmission or distribution. Recognizing this as a limitation of the analysis, the paper uses the estimates given in the respective studies as approximations of the long-run marginal cost of transmission and distribution for both rural and urban customers in Alberta. A study would need to be done on Alberta to determine the long-run marginal cost of transmission and distribution for each DFO.

Enmax and Epcor's energy charges are very similar to the incremental cost savings estimated by Cohen and Xcel. This means that it is likely that Enmax and Epcor's energy charge for distribution are close to the long-run marginal cost of distribution and would see smaller changes as a result of updated tariffs.[216]

All of the energy charges for transmission are much higher than the incremental cost of transmission calculated by Xcel energy (0.45 cents/kWh).[217] This result was already known from Chapter 12. A fixed charge is required to allow for a reduced energy charge set at the long-run marginal cost of transmission. A tariff consisting of only an energy charge is by definition too high for the transmission industry.

If all of Alberta's DFO's implemented a 0.81 cents/kWh charge for distribution and a 0.45 cents/kWh for transmission, it would reduce the incentive to install solar in all of the service areas. The energy charge for transmission and distribution is a driver of rooftop solar, and with Cohen and Xcel's low estimates of long-run marginal cost the incentive to install solar is reduced. This assumes Kost's forecast of solar cost declines and an 8.75 percent nominal discount rate.

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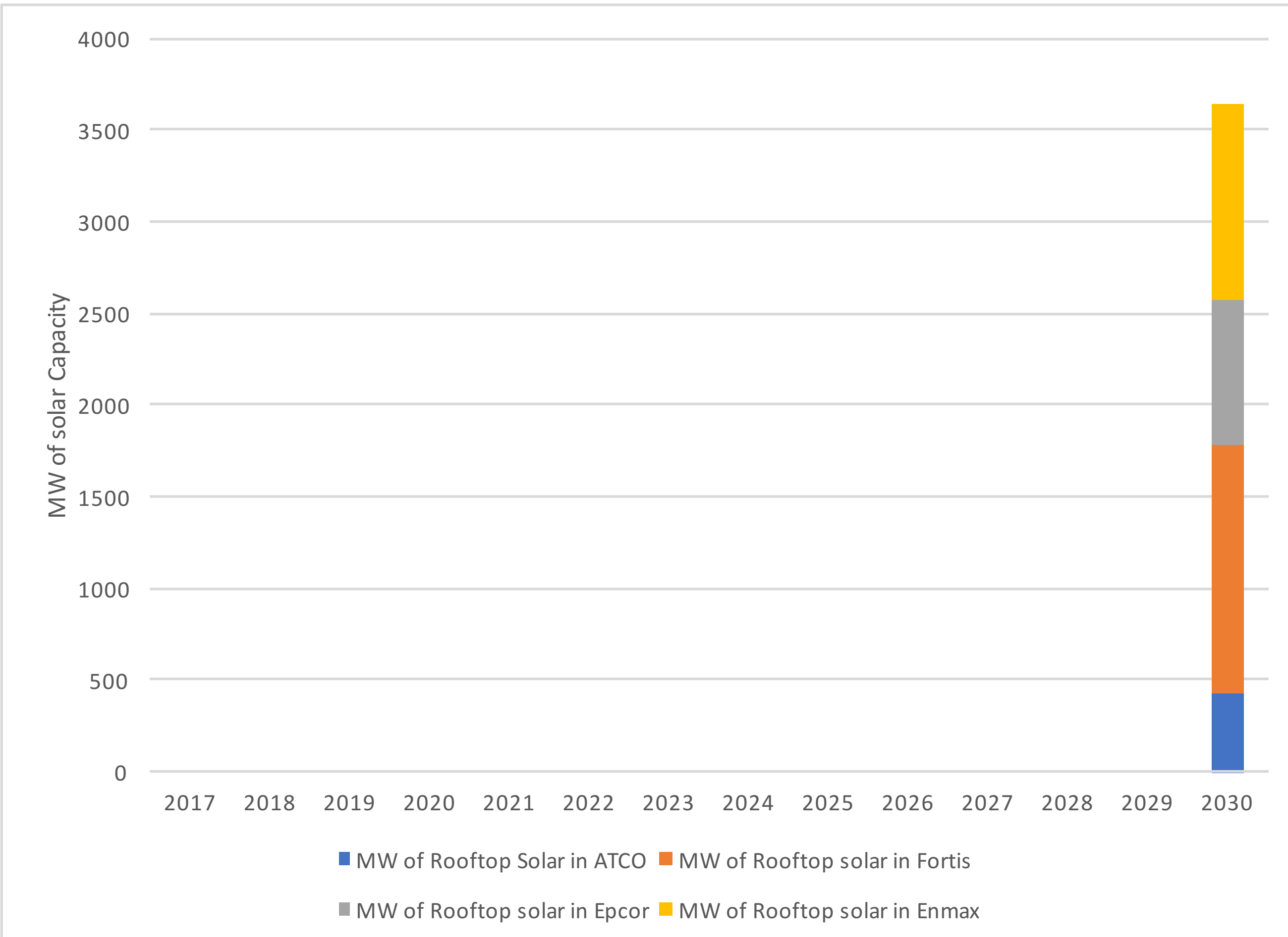
[216] See Table 1 in Chapter 5 for Residential distribution charges in ATCO, Fortis, Enmax and Epcor Service areas.
[217] See Table 1 for Residential transmission charges in ATCO, Fortis, Enmax and Epcor Service areas.

Figure 20 - Alberta Rooftop Solar Adoption with Efficient Tariffs (8.75% nominal discount rate)



3634 MW is installed by 2030 with efficient transmission and distribution tariffs. The reduced transmission and distribution tariffs push Fortis' substitution out to 2030. This is seven years later than Fortis substituted with the current tariffs (see Figure 3). ATCO also substitutes in 2030. This is four years later than with the current tariffs (see Figure 6). Enmax substitutes in 2030 and Epcor substitutes in 2030. The updated tariffs have a smaller impact on Epcor and

Enmax because those service areas already have tariffs that are close to the long-run marginal cost of distribution.

Table 26 shows the charges facing solar and non-solar customers in ATCO's 3rd quintile with the updated transmission and distribution charges. The transmission charge and the energy portion of the distribution charge are decreased to 0.45 cents/kWh and 0.81 cents/kWh, respectively. The energy portion of the distribution charge and the transmission charge are increased each year by the cost and inflation increases used in the TRIP workbook. The fixed charge for distribution is not updated and a fixed charge for transmission is not included because it does not impact the incentive to install solar. A residential customer needs to pay the fixed portion of the distribution charge and a fixed charge for transmission regardless of if they install a solar panel. For this reason, fixed charges are not updated in the calculation.

Table 26 - Annual Bill of ATCO Customer (3rd Quintile) with Efficient Tariffs

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I
		Solar	non-solar					
	Monthly Consumption (kWh)	0	508					
Unit*	Transmission charge $/kWh	Distribution Charge (fixed) $/month	Distribution charge variable $/kWh	Administration Fee $/month	Local Access Fee $/ month	Energy Cost $/month	Annual Electricity cost (Grid Electricity) $/year	Annual Electricity Cost (Grid electricity supplemented with solar) $/year
2017	0.0045	29.8	0.008	10	5	22	877	530
2018	0.0047	30.8	0.008	10	5	30	982	543
2019	0.0047	31.8	0.009	10	5	30	1001	556
2020	0.0048	32.9	0.009	10	5	37	1093	571
2021	0.0048	33.7	0.009	10	5	40	1149	582
2022	0.0048	34.8	0.009	10	5	53	1323	598
2023	0.0050	35.9	0.010	10	5	55	1364	613
2024	0.0050	37.1	0.010	10	5	55	1381	628
2025	0.0051	38.0	0.010	10	5	52	1358	639
2026	0.0051	39.2	0.011	11	5	57	1430	655
2027	0.0050	40.4	0.011	11	5	57	1447	671
2028	0.0050	41.6	0.011	11	5	57	1465	686
2029	0.0050	42.8	0.012	11	5	57	1482	702
2030	0.0049	44.0	0.012	11	5	57	1500	718
2031	0.0049	45.5	0.012	11	5	57	1522	738
2032	0.0049	46.8	0.013	11	5	57	1540	754
2033	0.0048	48.0	0.013	11	5	57	1558	770
2034	0.0048	49.5	0.013	11	5	57	1579	789
2035	0.0047	51.0	0.014	12	5	57	1600	808
2036	0.0047	52.5	0.014	12	5	57	1623	828
2037	0.0047	54.1	0.015	12	5	57	1646	849
2038	0.0047	55.8	0.015	12	5	57	1670	870
2039	0.0047	57.5	0.016	12	5	57	1695	892
2040	0.0047	59.2	0.016	12	5	57	1720	914
2041	0.0047	61.0	0.017	12	5	57	1746	938
2042	0.0048	62.8	0.017	12	5	57	1773	961
2043	0.0048	64.8	0.018	13	5	57	1801	986
2044	0.0048	66.7	0.018	13	5	57	1830	1011
2045	0.0048	68.7	0.019	13	5	57	1859	1037
2046	0.0048	70.8	0.019	13	5	57	1889	1064
2047	0.0048	73.0	0.020	13	5	57	1920	1091
2048	0.0048	75.2	0.020	13	5	57	1952	1119
2049	0.0048	77.5	0.021	13	5	57	1985	1148
2050	0.0048	79.8	0.022	14	5	57	2019	1178
2051	0.0049	82.2	0.022	14	5	57	2054	1209
2052	0.0049	84.7	0.023	14	5	57	2090	1241
2053	0.0049	87.3	0.024	14	5	57	2127	1273
2054	0.0049	89.9	0.024	14	5	57	2165	1307
2055	0.0049	92.6	0.025	14	5	57	2204	1342

Note: all values have been adjusted by a 2% inflation rate to set them at 2017 dollars. The PV calculation in Table 12 and 13 further adjusts these values using a real discount rate (6.6%).

The administration fee and local access fee are not updated because they would not be impacted by the change in the transmission and distribution tariff.

The energy cost (price of electricity) is left unchanged. Chapter 13 recommended to set the reimbursement price for excess solar production at the wholesale price of electricity. Residential customers would produce more electricity than they consume in the summer months, and they would produce less electricity than they consume in the winter months. With the updated reimbursement price, residential customer would receive the wholesale price of electricity for excess production in the summer months instead of the retail rate that they currently receive. This would further decrease the incentive to install solar because the wholesale rate is usually lower than the retail rate.

The model used in this paper cannot capture the monthly impact on residential customers because it calculates electricity costs on an annual basis. On an annual basis solar customers do not produce any electricity in excess of what they consume. Including the updated reimbursement price for solar customers would further erode the incentive to install solar. The results in this paper only analyze the impact of setting the distribution and transmission charges at the long-run marginal cost of distribution and transmission.

The impact of the updated tariffs is that solar customers do not save the same amount on transmission and distribution charges. With the current tariffs solar customers can avoid a large portion of their bill by installing solar because the transmission charge and the variable distribution charge is relatively high. With the new tariffs the savings are small and the incentive to install solar is reduced.

For the 3rd quintile in ATCO's service area the net present value of all electricity charges associated with installing solar are higher than using electricity exclusively from the grid for all years of the forecast. This leads to customers losing the incentive to install solar for all years. Table 27 uses Kost et al. forecast of solar cost declines.

Table 27 - ATCO's 3rd Quintile Solar Adoption with Transmission and Distribution Tariffs set at Long-Run Marginal Cost

Column A	Column B	Column C	Column D	Column E
Year	**Present Value total Non-solar***	**Present Value Total Solar***	**Difference***	**MW of capacity installed (MW)**
2017	$17,042	$26,873	($9,831)	0
2018	$17,616	$26,464	($8,848)	0
2019	$18,121	$26,080	($7,959)	0
2020	$18,647	$25,721	($7,074)	0
2021	$19,114	$25,385	($6,270)	0
2022	$19,560	$25,075	($5,516)	0
2023	$19,856	$24,789	($4,933)	0
2024	$20,135	$24,524	($4,390)	0
2025	$20,421	$24,283	($3,861)	0
2026	$20,758	$24,067	($3,309)	0
2027	$21,049	$23,874	($2,825)	0
2028	$21,348	$23,703	($2,356)	0
2029	$21,656	$23,555	($1,899)	0
2030	$21,974	$23,430	($1,456)	0
* All costs are stated in 2017 Canadian Dollars				

With the current tariffs ATCO customers in the 3rd quintile substitute to solar in 2030. This creates an inefficiency because with the updated tariffs customers in ATCO's 3rd quintile do not substitute in any of the years (as shown in Table 27). The ATCO customer installs solar with the current tariffs because the transmission and distribution tariffs are incorrect. The installation leads to an inefficiency because customers end up spending more money on electricity than is necessary.

The later substitution dates mean that the ATCO, Fortis, and Epcor customers that do install solar earlier than they would have with the updated tariffs are creating an inefficiency in Alberta's electricity market. The solar adoption with the current tariffs is compared to the solar adoption with efficient tariffs in Tables 28 and 29. The GWh of solar production under the current tariffs is compared to the GWh of solar installed with the updated efficient tariffs.

Table 28 - Current Tariff Solar Production Compared to Efficient Tariff Solar Production by DFO

	Current Tariffs	Efficient Tariffs	Current Tariffs	Efficient Tariffs	Current Tariffs	Efficient Tariffs	Current Tariffs	Efficient Tariffs
DFO	ATCO	ATCO	Fortis	Fortis	Epcor	Epcor	Enmax	Emmax
Unit	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2017	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	478	0	0	0	0	0	0	0
2027	484	0	0	0	0	0	0	0
2028	491	0	1743	0	0	0	0	0
2029	779	0	1768	0	0	0	0	0
2030	1015	505	3603	1793	1563	998	1368	1368

Table 29 - Total of current tariff solar adoption compared to efficient tariff solar adoption

	Current Tariffs	Efficient Tariffs	
Year	Total (GWh)	Total (GWh)	Difference
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	478	0	478
2027	484	0	484
2028	2234	0	2234
2029	2547	0	2547
2030	7548	4664	2885

Solar adoptions get pushed out as a result of the updated tariffs being lower than the current tariffs. The transmission and distribution savings associated with rooftop solar decrease and as a result the incentive to install solar also decreases.

When residential customers install solar earlier than they otherwise would have they incur additional electricity costs that are unnecessary. The efficient outcome is to use electricity from the grid. The inefficiency of adopting solar too early is the additional electricity costs incurred from the early installation.

The value of the inefficiency of rooftop solar is the cost difference between rooftop solar and grid electricity for years that saw rooftop solar adoption with the current tariffs but not with efficient tariffs. The cost difference between solar and grid electricity has already been calculated in the solar forecast (see Table 27 Column D for an example). The cost difference for customers in each quintile of each distribution service area can be multiplied by the number of customers adopting solar. This creates the aggregate inefficiency associated with rooftop solar for each distribution service area in Alberta.

The value of the inefficiency for ATCO's 3rd quintile is shown in Table 30. Column D in Table 30 is the cost difference between solar and grid electricity over the 25 years of the investment. This is the same as column D in Table 27. Column E in Table 30 is the number of customers in ATCO's 3rd quintile that substitute to solar in 2030. Only 2030 is shown because this is the only year that has an inefficiency. Column F multiplies Column A by Column C to calculate the inefficiency associated with rooftop solar for each year of the forecast.

Table 30 - Rooftop Solar Inefficiency for ATCO's 3rd Quintile

Column A	Column B	Column C	Column D	Column E	Column F
Year	Substitution with current tariff (MW)	Substitution with efficient tariffs (MW)	Present Value of difference between solar and non-solar electricity using efficient tariffs (2017 dollars)	Number of Sites substituting to Solar in ATCO's 3rd Quintile in each year	Total Cost (Column D * Column E) - 2017 dollars)
2017	0	0	($9,831)		$0
2018	0	0	($8,848)		$0
2019	0	0	($7,959)		$0
2020	0	0	($7,074)		$0
2021	0	0	($6,270)		$0
2022	0	0	($5,516)		$0
2023	0	0	($4,933)		$0
2024	0	0	($4,390)		$0
2025	0	0	($3,861)		$0
2026	0	0	($3,309)		$0
2027	0	0	($2,825)		$0
2028	0	0	($2,356)		$0
2029	0	0	($1,899)		$0
2030	189	0	($1,456)	36826	$53,606,920.04
				Present Value	$23,304,652.72
				Real Interest Rate	6.6%

The present value of the inefficiency of solar for ATCO's 3rd quintile is 23 million dollars (2017 dollars). There is an efficiency in 2030 because ATCO's 3rd quintile substitutes to solar in 2030 with the current tariffs, but they do not substitute to solar by 2030 with the updated tariffs.

The present value calculation in Table 30 discounts $53,606,920 back 13 periods $53,606,920/(1.066176471)^(13)=23,304,653 . The values in Column D occur at the beginning of the period, so it is necessary to discount $53,606,920 back thirteen years to represent the costs at the beginning of 2017.

ATCO's 5th quintile is also shown as an example. In the case of ATCO's 5th quintile the inefficiency is the additional electricity costs incurred by the customer as a result of not delaying the solar investment.

Table 31 shows why the inefficiency for ATCO's 5th quintile is the additional cost of not delaying the solar investment. Table 31 compares the installation of solar under the current tariffs (Column B) and updated efficient tariffs (Column C). Under the current tariffs solar adoption starts in 2026. Ignoring the incentive to wait, there are positive earnings associated with solar starting in 2017 (Column D). If the incentive to wait is considered, residential customers do not have an incentive to install solar before 2026.

Using the efficient tariffs the earnings associated with solar (excluding the incentive to wait) become positive in 2025. Column D and E do not include the benefit of delaying the solar investment. With the incentive to wait, the solar adoptions do not occur before 2030. In the case of ATCO's 5th quintile, even when the efficient transmission and distribution tariffs are considered, solar is a cheaper form of electricity compared to grid electricity 2025 and onwards. The opportunity of installing solar in 2025 and onwards is not the alternative option of using the grid exclusively but the alternative option of installing solar at a later date. There are higher earnings associated with installing solar a year later. The inefficiency of ATCO's 5th quintile substituting in 2026 instead of 2030 is the lost solar earnings that could have been earned from delaying.

Table 31 - Solar Adoption with Current Tariffs compared to Solar Adoption with Efficient tariffs (ATCO's 5th Quintile)

Column A	Column B	Column C	Column D	Column E
Year	Substitution with current tariff (MW)	Substitution with efficient tariffs (MW)	Present Value of difference between solar and non-solar electricity using current tariffs (2017 dollars)	Present Value of difference between solar and non-solar electricity using efficient tariffs (2017 dollars)
2017	0	0	$9,368	($10,037)
2018	0	0	$11,621	($8,228)
2019	0	0	$13,666	($6,618)
2020	0	0	$15,726	($5,006)
2021	0	0	$17,622	($3,562)
2022	0	0	$19,437	($2,216)
2023	0	0	$20,888	($1,246)
2024	0	0	$22,254	($353)
2025	0	0	$23,609	$517
2026	403	0	$25,044	$1,453
2027	408	0	$26,344	$2,244
2028	414	0	$27,642	$3,013
2029	420	0	$28,939	$3,762
2030	426	426	$30,237	$4,491

The inefficiency associated with ATCO 5th Quintile adopting early is demonstrated using equations. The equations use a simple example where the solar investment only lasts 3 years.

Equation 27 : NPV(install year 2) = $-K_2/(1 + r) + Profit_2/(1 + r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4$

Equation 28: NPV(install in year 3) = $-K_3/(1+r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4 + Profit_5/(1+r)^5$

Equation 27 is the net present value of earnings of a residential customer that installs solar in year 2. Equation 28 is the net present value of earnings of a residential customer that installs solar in year 3. If the customer delays the investment 1 year, they will earn a return in the fourth year. This is accounted for in the '$Profit_4/(1+r)^4$' term. If the customer delays the investment 2 years, the customer will earn a return on investment in the fifth year. This is accounted for in the '$Profit_5/(1+r)^5$' term.

The customer has chosen to adopt solar in the 2nd year. The earnings from this option are given in Equation 27. The lower cost option is to install solar in the 3rd year. The earnings of this route are given in Equation 2. The reason that the customer choose to install in the 2nd year rather than the 3rd year is that the customer faces incorrect price signals. The purpose of the calculation is to determine the difference between the two options (inefficiency). The value of the inefficiency is the difference between Equation 27 and Equation 28.

Equation 29: NPV(install in year 3) – NPV(install in year 2) = inefficiency

Equation 30: $-K_3/(1+r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4 + Profit_5/(1+r)^5 – (-K_2/(1 + r) + Profit_2/(1 + r)^2 + Profit_3/(1+r)^3 + Profit_4/(1+r)^4) = inefficiency$

By cancelling out the profit in the third and fourth period on the left hand side of the equation you get:

Equation 31: $-K_3/(1+r)^2 + Profit_5/(1+r)^5 – (-K_2/(1 + r) + Profit_2/(1 + r)^2) = inefficiency$

Carrying out the negative sign:

Equation 31: $-K_3/(1+r)^2 + Profit_5/(1+r)^5 + K_2/(1 + r) - Profit_2/(1 + r)^2 = inefficiency$

Rearrange:

Equation 33: $K_2/(1 + r) - K_3/(1+r)^2 - Profit_2/(1 + r)^2 + Profit_5/(1+r)^5 = inefficiency$

Multiply by (1+r):

Equation 34: $K_2 - K_3/(1+r) - Profit_2/(1 + r) + Profit_5/(1+r)^4 = (1+r)*inefficiency$

Equation 34 is the value of the inefficiency at the beginning of year 2. The 'inefficiency' term is the inefficiency at the beginning of year 1. '(1+r)*inefficiency' is the inefficiency at the beginning of year 2. Calculating the inefficiency in year 2 in this example creates the same discounting as Table 32 below.

The term '$K_2 - K_3/(1+r)$' in Equation 34 is the cost decrease from delaying the solar investment one year. The benefit of delaying one year is that the cost decreases to K_3 and the solar cost is pushed out 1 year into the future. The term '$Profit_2/(1 + r)$' is the lost profit from delaying one year and the term '$Profit_5/(1+r)^4$' is the additional earnings in the last period from delaying the investment.

By manipulating Equation 34, we get the same format that is used in Table 32.

Multiply by (1+r):

Equation 35: $(1+r)*K_2 - K_3 – Profit_2 + Profit_5/(1+r)^3 = (1+r)^2*inefficiency$

Multiply out (1+r) into K_2:

Equation 36: $K_2 + r*K_2 – K_3 – Profit_2 + Profit_5/(1+r)^3 = (1+r)^2*inefficiency$

Rearrange:

Equation 37: $r*K_2 + K_2 – K_3 – Profit_2 + Profit_5/(1+r)^3 = (1+r)^2*inefficiency$

Multiply and divide by K_2:

Equation 38: $r*K_2 + (K_2 – K_3)/K_2 * K_2 – Profit_2 + Profit_5/(1+r)^3 = (1+r)^2*inefficiency$

Substitute in $q_3 = (K_2 – K_3)/K_2$

Equation 39: $r*K_2 + q_3 * K_2 – Profit_2 + Profit_5/(1+r)^3 = (1+r)^2*inefficiency$

Equation 39 is the inefficiency associated with not delaying the solar investment at the end of the second year. The equation states what the difference in earnings is between installing at the beginning of year 2 and delaying and installing at the beginning of year 3. Equation 39 is generalized and set to the investment period of the solar investment (25 years) in Equation 40.

Equation 40: $r*K_x + q_{x+1} * K_x – Profit_x + Profit_{x+25}/(1+r)^25 = inefficiency(end\ of\ year\ x)$

In the case of ATCO's 5th quintile, solar has become a lower cost form of electricity compared to grid electricity by 2025 (see Column E of Table 31). The inefficiency of solar is not that it is a higher cost form of electricity compared to grid electricity but that solar installations in that year are a higher cost form of electricity compared to delaying solar to a later year. The earnings associated with solar in 2026 are lower than the earnings associated with delaying the installation by one year. The opportunity cost of installing solar one year too early is the inefficiency of solar.

Table 32 shows the lost earnings associated with installing solar one year earlier. It is the left hand side of Equation 40. The net benefit of waiting one year decreases each year until waiting becomes a cost in 2030. At this point the customer has an incentive to install solar. With the exception of Column A, all values in Table 32 occur at the end of the year. These values are discounted back to the start of the year in Table 33.

Table 32 - Benefit of Waiting for ATCO's 5th Quintile

	Column A	Column B	Column C	Column D	Column E	Column F	Column G
	K(x)	K(x)*r	q	K(x)*q	Profit(x+25)/(1+r)^25	Profit (x)	Column B + Column D + Column E - Column F
2017	$29,242	$1,935	3.3%	$977	$368.05	$780	$2,501
2018	$28,265	$1,870	3.3%	$944	$369.51	$989	$2,196
2019	$27,321	$1,808	3.3%	$913	$371.01	$1,000	$2,092
2020	$26,408	$1,748	3.3%	$882	$372.55	$1,174	$1,828
2021	$25,526	$1,689	3.3%	$853	$374.15	$1,275	$1,641
2022	$24,673	$1,633	3.3%	$824	$375.79	$1,632	$1,200
2023	$23,849	$1,578	3.3%	$797	$377.47	$1,691	$1,062
2024	$23,052	$1,526	3.3%	$770	$379.21	$1,694	$981
2025	$22,282	$1,475	3.3%	$744	$381.00	$1,617	$983
2026	$21,538	$1,425	3.3%	$720	$382.85	$1,743	$785
2027	$20,818	$1,378	3.3%	$695	$384.75	$1,747	$711
2028	$20,123	$1,332	3.3%	$672	$386.70	$1,751	$640
2029	$19,450	$1,287	3.3%	$650	$388.72	$1,755	$571
2030	$18,801	$1,244	0.0%	$0	$390.79	$1,759	($124)

The inefficiency associated with ATCO's 5th quintile substituting in 2026 is that there is a benefit associated with waiting until 2030. The benefit of waiting one year is calculated in Column G of Table 32. The annual benefit of waiting is the annual inefficiency of installing solar too early. In the case of ATCO's 5th quintile there is an inefficiency associated with installing solar in 2026, 2027, 2028 and 2029. The annual per customer value of the inefficiency is Column G in Table 32.

Column G in Table 32 is used in Table 33 to calculate the inefficiency associated with ATCO's 5th quintile substituting too early.

Table 33 - Inefficiency of ATCO's 5th Quintile Substituting to Solar

	Annual benefit of waiting one year to install solar	Number of Customers in ATCO's 5th Quintile	Annual Innefficiency of Intalling Solar too early
2017	$2,501	30737	0
2018	$2,196	31167	0
2019	$2,092	31604	0
2020	$1,828	32046	0
2021	$1,641	32495	0
2022	$1,200	32950	0
2023	$1,062	33411	0
2024	$981	33879	0
2025	$983	34353	0
2026	$785	34834	$ 27,330,789
2027	$711	35322	$ 25,112,231
2028	$640	35816	$ 22,912,261
2029	$571	36318	$ 20,729,709
2030	($124)	36826	0
		Present Value	$ 46,441,504

The annual inefficiency values in Table 33 occur at the end of each period. The present value calculation discounts each annual value back an additional year to bring the cost back to the beginning of 2017. As an example the inefficiency in 2026 is discounted back 10 periods to bring it back to the beginning of 2017.

The inefficiency of ATCO's 5th Quintile substituting too early is 46 million dollars (2017 dollars). This is the lost earnings as a result of substituting to solar too early.

The calculation showed for ATCO's 3rd quintile and ATCO's 5th quintile is done for the 4th quintile in ATCO's service area and for Fortis, and Epcor. The value of the annual inefficiency is calculated for years that saw substitution with the current tariff but not with the updated efficient tariff. Table 34 shows the total inefficiency for each DFO for each year of the forecast. The present value of the inefficiency calculated using a 6.6% real interest rate.

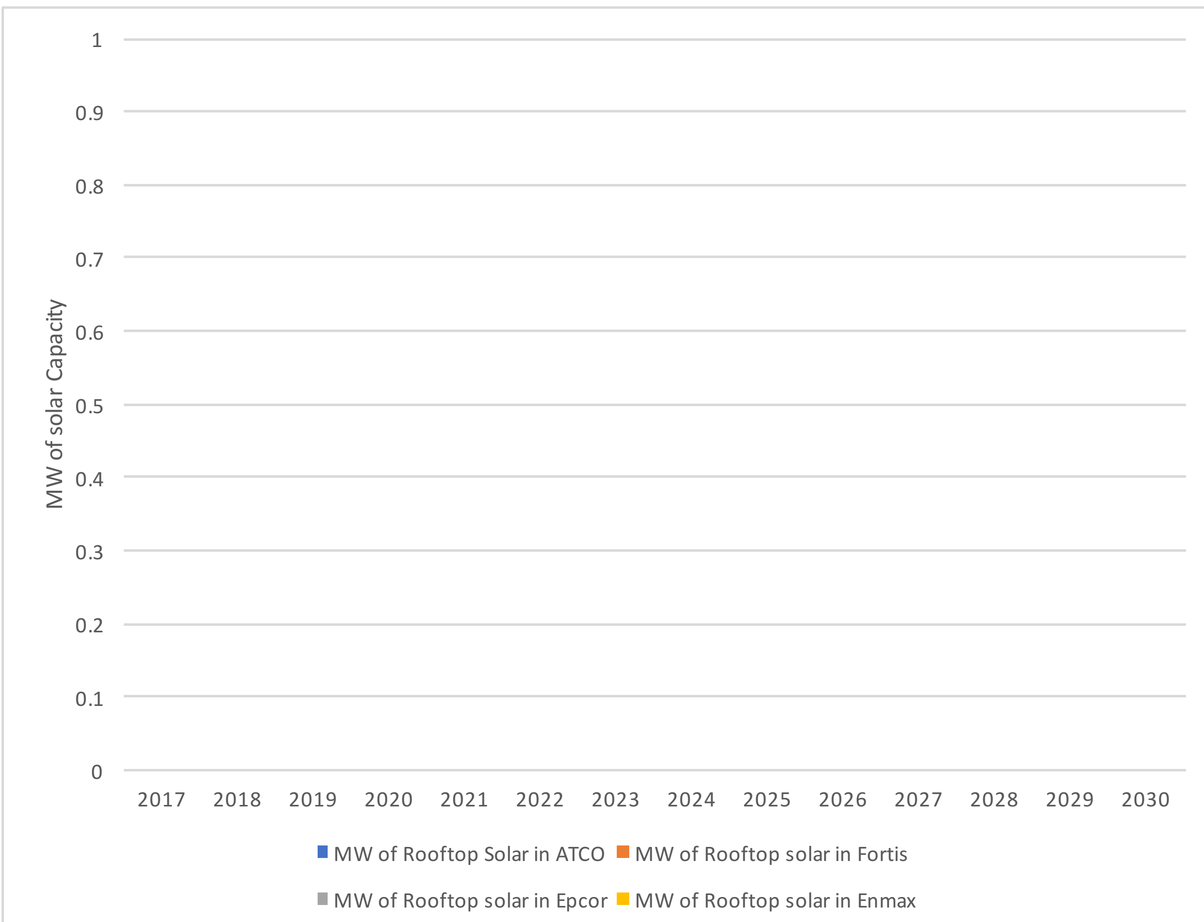
Table 34 Inefficiency of Rooftop Solar in Alberta (8.75% nominal discount rate)

	Additional ATCO Costs (2017 dollars)	Additional Fortis Costs (2017 dollars)	Additional Epcor Costs (2017 dollars)	Additional Enmax Costs (2017 dollars)	Total (2017 dollars)
2017	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -
2026	$ 25,634,395	$ -	$ -	$ -	$ 25,634,395
2027	$ 23,553,541	$ -	$ -	$ -	$ 23,553,541
2028	$ 21,490,120	$ 119,651,835	$ -	$ -	$ 141,141,956
2029	$ 29,028,097	$ 108,268,883	$ -	$ -	$ 137,296,980
2030	$ 53,606,920	$ 25,281,294	$ 81,328,711	$ -	$ 160,216,925
Real Interest rate	6.6%			Present Value	$ 229,847,237

Installing rooftop solar using the current tariff structure results in Albertans spending 230 million dollars (2017 dollars) in additional electricity costs. The 230 million dollar estimate assumes that the long-run marginal cost studies in California and Colorado can be applied to Alberta. A study would need to be done for Alberta specifically to determine the current long-run marginal cost of distribution and transmission in the province. Cohen and Xcel provide a reference for the current energy charge for distribution in Alberta.

A sensitivity analysis is done using the 12.75% nominal discount rate. When the current tariffs are used, Fortis' 5th and 4th quintiles substitute in 2030 (see Figure 11). With the updated efficient tariffs no Fortis customers substitute by 2030. ATCO's substitution date also gets pushed out as a result of the lower transmission and distribution charges. With the current tariffs, ATCO substitutes in 2027 (see Figure 11). With the updated efficient tariffs no ATCO customers substitute by 2030. Enmax and Epcor's substitution dates are not impact by the change in the transmission and distribution charge. In both cases (current and updated tariffs), Enmax and EPCOR customers do not substitute to solar.

Figure 21 - Alberta Rooftop Solar Adoption with Efficient Tariffs (12.75% Nominal Discount Rate)



The 230 million dollar estimate done in Table 34 uses the base forecast from Chapter 6. Table 35 provides the inefficiency calculation using the 12.75 percent nominal discount rate sensitivity in Chapter 6.

Table 35 - Inefficiency of Rooftop Solar in Alberta (12.75% nominal discount rate)

	Additional ATCO Costs (2017 dollars)	Additional Fortis Costs (2017 dollars)	Additional Epcor Costs (2017 dollars)	Additional Enmax Costs (2017 dollars)	Total (2017 dollars)
2017	$ -	$ -			$0
2018	$ -	$ -			$0
2019	$ -	$ -			$0
2020	$ -	$ -			$0
2021	$ -	$ -			$0
2022	$ -	$ -			$0
2023	$ -	$ -			$0
2024	$ -	$ -			$0
2025	$ -	$ -			$0
2026	$ -	$ -			$0
2027	$ 159,838,508	$ -			$159,838,508
2028	$ 1,872,462	$ -			$1,872,462
2029	$ 1,539,079	$ -			$1,539,079
2030	$ 267,790,228	$ 301,132,454			$568,922,682
Real Interest rate	10.5%			Present Value	$ 214,414,667

In the 12.75% nominal discount rate scenario, if the tariffs are updated to the long-run marginal cost of transmission and distribution, then the incentive to install solar entirely disappears (see Figure 21). The solar installations that occur with the current tariffs create an inefficiency in Alberta's electricity market. The value of that inefficiency is calculated in Table 35 (214 million dollars).

The inefficiency associated with rooftop solar decreases when the 12.75 percent nominal discount rate is used. This result is intuitive in that the increased discount rate decreases the value of future costs (inefficiencies).

If the cost estimates from Colorado and California can be applied to Alberta, and residential customers have an 8.75% nominal discount rate, there is 2244 MW of solar that will be installed in 2030 with the current tariff design that is not needed. If the 12.75% nominal discount rate is used, then there is 2965 MW of solar that is installed in 2030 with the current tariff design that is not needed.[218] It would be cheaper to use electricity from the grid and defer these solar installations to a later year. The result is Albertans paying between 214 and 230 million dollars in additional electricity costs than is necessary, depending on the nominal discount rate used.

If rooftop solar investments are deferred to a later year, this would have implications for constructing commercial scale generation in the province. Commercial generators may not be willing to invest if rooftops solar will come on the grid and erode the pool price at a later date.

The reason that installing rooftop solar costs Albertans an additional 214 to 230 million dollars over the next thirteen years is that solar is a high cost form of electricity compared to grid electricity. The capital investment necessary to install solar is larger than the cost of consuming electricity from the grid. While rooftop solar does provide some savings in transmission and

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[218] 5878 MW – 3634 MW = 2244 MW
2965 MW – 0 MW = 2965MW

distribution costs, it is not large enough to cover the high generation cost associated with rooftop solar.

The estimates made in this paper are a conservative estimate of the inefficiency associated with rooftop solar. By taking the long-run perspective when calculating the inefficiency of solar, the sunk costs associated with the transmission and distribution network are assumed to be avoidable. In reality, a lot of these costs have already been invested and there is no opportunity to avoid them. This means that the savings associated with rooftop solar on the transmission and distribution network are much lower in the short run. Capacity costs associated with transmission and distribution are sunk in the short run and cannot be avoided. This paper makes a conservative estimate of the inefficiency associated with solar by assuming that the capacity costs are avoidable.

The paper also assumes that generation costs are avoidable. When the inefficiency calculation was made, the value of solar power is the price of electricity. As was discussed in Chapter 13, the price of electricity represents the long-run marginal cost of generation (see page 174). In reality, a lot of the generation costs are already sunk in the short run and cannot be avoided. The paper makes a conservative estimate of the inefficiency associated with rooftop solar by assuming that all generation costs are avoidable.

Residential customers respond to incorrect price signals in the transmission and distribution market that understate the cost of rooftop solar. The current tariffs communicate large savings in transmission and distribution costs. In reality, the savings on the transmission and distribution network from installing solar are relatively small. The small savings in transmission and distribution and the large additional generation costs associated with rooftop solar lead to 214 to 230 million dollars of additional electricity costs over the next thirteen years.

15.3 Cost of Carbon

Alberta currently has a carbon levy for carbon produced in the electricity sector. The current carbon levy is set at $30/tonne of carbon emissions. The carbon tax is scheduled to increase to $40/tonne in 2021.[219] The electricity price forecast used for the solar forecast is sourced from a report published by the AESO.[220] It is reasonable to assume that the price forecast used in the paper includes the current carbon tax and the future carbon tax increases (this is not specifically stated in the report). Given that this is the case, the inefficiency calculation of rooftop solar in Tables 34 and 35 includes the cost of carbon. The cost of carbon emissions from consuming electricity from the grid is embedded in the electricity price. By installing rooftop solar, the customer avoids consuming electricity from the grid and as a result the cost of carbon is not incurred. Rooftop solar does not emit carbon when it produces electricity, and would not pay a carbon tax.

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[219] Wood, J. (2017). "Carbon tax set to increase to $30 per tonne in 2018; no further increases until 2021." Retrieved April 27th, 2018, from http://calgaryherald.com/news/politics/carbon-tax-set-to-increase-to-30-per-tonne-in-2018-no-further-increases-until-2021.

[220] AESO (2017). "Transmission Rate Projection." Retrieved February 13th, 2017, from https://www.aeso.ca/assets/Uploads/TRP-Factsheet-WEB.PDF.

15.4 Impact on Fixed Charges for Transmission and Distribution in Alberta

Setting the variable charge for transmission to the long-run marginal cost of transmission would require the introduction of a fixed charge. As was explained in Chapter 12, if the variable charge is set at the long-run marginal cost of transmission, a fixed charge must be introduced to cover the costs of the firm.

Table 36 approximates how much the fixed charge for transmission for each of the DFOs would need to be to recover the same amount of revenue that is currently collected with the variable charge. The approximation is done by calculating how much the average customer's fixed charge would need to increase in order for the DFO to collect the same amount of revenue from that customer. The kWh consumed per month by the 3rd ATCO quintile is used for all DFOs (508 kWh). Fortis' fixed charge for transmission increases the most. If the variable charge for transmission was set at the long-run marginal cost of transmission (\$0.0045 /kWh), Fortis would need to implement a fixed charge set at 17 dollars per month in 2017.

Table 36 - Fixed Transmission Charges for ATCO, Fortis, Enmax and Epcor

Monthly Consumption (kWh)	508			
$/month	DFO	Revenue Received from Current Transmission Tariff	Revenue Received from Efficient Tranmission Tariff	Change in Fixed Charge
Variable ($/month)	ATCO	$ 18	$ 2	
Fixed ($/month)	ATCO	$ -	$ 16	$ 16
Variable ($/month)	Fortis	$ 19	$ 2	
Fixed ($/month)	Fortis	$ -	$ 17	$ 17
Variable ($/month)	Epcor	$ 16	$ 2	
Fixed ($/month)	Epcor	$ -	$ 13	$ 13
Variable ($/month)	Enmax	$ 10	$ 2	
Fixed ($/month)	Enmax	$ -	$ 8	$ 8

Fixed charges for distribution would also need to increase if the variable charge was set at the long-run marginal cost of distribution ($0.0081 / kWh). Table 37 shows the increase in the fixed charge required to collect the same amount of revenue that the current tariff collects. The monthly consumption of ATCO 3rd quintile is used. ATCO would experience the largest increase in their fixed distribution charge if the variable distribution charge was set at $0.0081 / kWh. Epcor would not experience any increase in their fixed charge because their current distribution tariff is already very close to $0.0081 / kWh.

The increase in the fixed fee might cause the low use consumers to disconnect from the grid. The increase in the fixed charge would have a large effect on the total electricity charges faced by that group of customers. If those low use consumers are also low income, the customers might not be able to afford to stay on the network. The disconnection would be motivated by an inability to pay the high fixed charge of using electricity. This could be avoided by subsidizing these customers to stay on the network. Low income customers could apply for a reduction in the fixed charge based on their level of income. Only those customers that cannot afford to stay on the network would be given a subsidy.

Table 37 - Fixed Distribution Charges for ATCO, Fortis, Enmax and Epcor

Monthly Consumption (kWh)	508			
$/month	DFO	Revenue Received from Current Distribution Tariff	Revenue Received from Efficient Distribution Tariff	Change in Fixed Charge
Variable ($/month)	ATCO	$ 34	$ 4	
Fixed ($/month)	ATCO	$ 30	$ 59	$ 29
Variable ($/month)	Fortis	$ 10	$ 4	
Fixed ($/month)	Fortis	$ 21	$ 27	$ 6
Variable ($/month)	Epcor	$ 4	$ 4	
Fixed ($/month)	Epcor	$ 18	$ 18	$ 0
Variable ($/month)	Enmax	$ 5	$ 4	
Fixed ($/month)	Enmax	$ 15	$ 16	$ 1

Chapter 16 Tariff and Electricity Price Redesigns in Arizona, Hawaii and Alberta

There are examples of other jurisdictions that are further along in the process of updating tariffs in response to growth in rooftop solar. Arizona is an example of a state that redesigned their transmission and distribution tariffs in response to increased rooftop solar adoption. Another example is Hawaii which redesigned their reimbursement price for excess rooftop solar production. Alberta is also in the process of reviewing their distribution and transmission tariffs. The Alberta Utilities Commission has conducted a broad review into distributed generation which could lead to a redesign of Alberta's reimbursement price for electricity produced by rooftop solar and Alberta's residential transmission and distribution tariffs.

16.1 Arizona's Experience

Arizona has many relevant examples of designing tariffs with a high penetration of rooftop solar. Salt River Project is a good example of a utility that has designed tariffs specifically for rooftop solar customers.

The solar penetration in Arizona is high relative to other states in the US. In 2016, 1.5 percent of Arizona's electricity was sourced from Photovoltaic (PV) distributed generation (DG). In comparison, 7.8 percent of Hawaii's electricity in 2016 came from PV DG and 0.9 percent of Colorado's electricity came from PV DG.[221]

Most utilities in Arizona are vertically integrated. This means that they provide all services related to electricity to its customers: generation, transmission, distribution and retail.[222] The Arizona Corporate Commission regulates many of the utilities in Arizona. The two utilities servicing the city of Phoenix are Arizona Public Service Company and Salt River Project Agricultural Improvement and Power District (SRP). Arizona Public Service Company is regulated by the Arizona Corporate Commission (ACC) while the SRP is not.[223] SRP's electricity rates are approved by its own board. The ACC does not regulate SRP because it is designated as a quasi-municipality.[224]

SRP is currently a legal dispute against SolarCity. SolarCity is the USA's largest installer of distributed solar energy systems. SolarCity took SRP to court after SRP increased their

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[221] Anderson, C. (2016). "Solar Leaderboard." Retrieved March 30th, 2017, from http://www.solarleaderboard.com/2016-solar-penetration-state/.

623973MWh/7982639MWh=0.078
1427970/93456444=0.015
412835/45125443=0.009

[222] Federal Energy Regulatory Commission. "Electric Power Markets: National Overview." Retrieved June 30, 2017, from https://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

[223] Arizona Corporate Commission. "General Electric Information." Retrieved June 30th, 2017, from http://www.azcc.gov/divisions/utilities/electric/gen_info.asp.

[224] Arizona Corporate Commission. "Who Regulates Salt River Project (SRP)." Retrieved June 30, 2017, from http://www.azcc.gov/divisions/utilities/electric/srp.asp.

electricity rates for customers with rooftop solar panels. Customers with rooftop solar experienced nearly a 65 percent rate increase.

After SRP introduced the new tariffs, the incentives to install solar were significantly less and SolarCity's business suffered as a result. As a response to the tariff changes, SolarCity applied to the court for damages and injunctive relief under federal and state antitrust laws.

SolarCity argued that SRP was maintaining their monopoly when they increased electricity rates for solar customers. SRP argued that it is immune from anti-trust damages claims under federal and state law.[225] The legal battle between the two parties is currently continuing (SolarCity and SRP) has not yet been resolved.

SRP currently offers three major electricity plans: time-of-use tariff, basic, and customer generation plan. Basic plan is designed for customers without access to a smart meter on their home. It includes a fixed monthly fee to cover the cost of billing and collections, metering, customer service, and some distribution costs. There is also an energy charge (per kWh) to cover the cost of transmission, distribution, ancillary services, generation, and fuel/purchased power.[226]

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[225] United States District Court (October 27, 2015.). "SolarCity Corporation, Plaintiff,
v.
Salt River Project Agricultural Improvement and Power District, et al., Defendants.".

[226] SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT (2015). "E-23 STANDARD PRICE PLAN FOR RESIDENTIAL SERVICE ". Retrieved July 4th, 2017, from http://www.srpnet.com/prices/pdfx/April2015/E-23.pdf.

The Time-of-use tariff is designed for customers with access to a smart meter. It has the same fixed charge for billing and collections, metering, customer service, and some distribution costs. The kWh charge charges based on on-peak or off-peak consumption. On-peak consumption receives a higher charge than off-peak.[227]

Customer generation plan is the time-of-use plan but with a larger fixed fee and a lower kWh charge. Customers with on-site generation must adopt this plan and must install a smart meter to allow for the tariff to be applied.[228]

SRP's actions are very similar to the recommendations made in this paper. SRP's reduced its energy charge for transmission and distribution. It is likely that this resulted in an energy charge that is closer to the long-run marginal cost of transmission and distribution. A consequence of redesigning the tariffs was that it reduced the incentive to install rooftop solar.

Updated tariffs allow residential customers to compare the cost of using the network to alternative like rooftop solar. Marginal cost tariffs communicate that the marginal cost of using the network is very small. Rooftop solar does not provide significant cost savings in transmission

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[227] SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT (2015). "E-26 STANDARD PRICE PLAN FOR RESIDENTIAL TIME-OF-USE SERVICE ". Retrieved July 4th, 2017, from http://www.srpnet.com/prices/pdfx/April2015/E-26.pdf.

[228] SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT (2015). "E-27 CUSTOMER GENERATION PRICE PLAN FOR RESIDENTIAL SERVICE ". Retrieved July 4th, 2017, from https://www.srpnet.com/prices/pdfx/April2015/E-27.pdf.

and distribution. Without updated tariffs, consumers are not incented to choose the lowest cost form of electricity.

Alberta can learn from Arizona's experience. It is essential to anticipate growth in new technologies like rooftop solar. Distribution and transmission tariff design has a huge impact on rooftop solar adoption. Customers rely on efficient and consistent tariffs to make decisions concerning electricity investments like rooftop solar. Changing tariffs too late in the process leads to legal disputes like the one in Arizona.

16.2 Hawaii's Reimbursement Price for Rooftop Solar

Hawaii updated the price that solar customers receive for the electricity that they put back onto the grid.[229] The hearing from Hawaii provides some context to the recommendation made in this paper.

The Hawaii Public Utilities Commission (PUC) regulates Hawaii's electricity system. There are four vertically integrated utilities that provide electricity to the six major islands of Hawaii. Hawaiian Electric Company (HECO) is one of those four utilities.[230]

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[229] Hawaii Public Utilities Commission. ""PUC Reforms Energy Programs to Support Future Sustainable Growth in Hawaii Rooftop Solar Market"." Retrieved September 1st, 2016, from http://puc.hawaii.gov/wp-content/uploads/2015/10/DER-Phase-1-DO-Summary.pdf.

[230] Hawaii Public Utilities Commission (2016). "State of Hawaii Public Utilities Commission." Retrieved September 30, 2016, from http://puc.hawaii.gov/energy/.

The five largest charges on a typical bill for a residential customer served by the HECO are the customer charge, the base fuel energy charge, the non-fuel energy charge, the energy adjustment charge, and the purchase power adjustment charge.

The customer charge is a fixed monthly charge and it covers the cost of billing and metering. The base fuel charge is paid by residential consumers, per KWh, and covers the cost of fuel incurred by HECO. The non-fuel energy charge is a per KWh charge and it covers the non-fuel costs of generation, transmission and distribution. The energy cost adjustment rate adjusts the base fuel charge based on the current price of fuel. The purchase power adjustment covers taxes faced by the utility.[231]

Under Hawaii's Net Energy Metering (NEM), residential customers receive a credit for the electricity they produce equal to the energy charge (base fuel and non-fuel charge), and any adjustments applicable to the energy charge (energy cost adjustment). The credit can only be applied to the energy charge, and adjustments to the energy charge. Regardless of the amount of electricity produced, the solar customer pays a minimum charge to be connected to the network.[232]

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[231] Hawaiian Electric. "Understanding Elements of Your Bill." Retrieved September 27th, 2016, from https://www.hawaiianelectric.com/my-account/understanding-your-bill/understanding-elements-of-your-bill.

[232] Hawaiian Electric Company Inc (2014). "Rule No. 18 Net Energy Metering." Retrieved September 30, 2016, from https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rules/18.pdf.

In 2015 the HECO companies elected to update the NEM tariff with the new 'Customer Grid Supply Option'. The grid supply option reduces the credit provided by NEM to a rate that approximates the relative value of electricity exported to the grid.[233]

The grid supply option uses the average on-peak avoided cost of electricity as the price that solar consumers receive for the electricity they produce.[234] The average on-peak avoided cost of electricity is determined by calculating the fuel costs, generation operations and maintenance costs, and transmission line loses that the utility avoids when a rooftop solar panel produces electricity.[235]

As indicated in the title, the average on-peak avoided cost of electricity represents the costs that a utility avoids when it receives electricity from a rooftop solar panel. It approximates the short-run marginal cost of production for a fossil fuel generator. Variable costs like line losses and fuel costs are included but the cost of capacity is not.

The PUC argued that the average on-peak avoided cost of electricity is also a reasonable estimate of the cost of utility scale renewable projects. The purpose of updating the reimbursement price of electricity for rooftop solar is to incent the lowest cost form of electricity to be installed. The

[233] Hawaii Public Utilities Commission (2015). "DECISION AND ORDER NO. 33258 ". Retrieved September 12th, 2016, from http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15J13B15422F9046418+A15J13B31859H489831+14+1960.

[234] Ibid.

[235] Hawaii Public Utilities Commission (2008). "DECISION AND ORDER NO. 24086 DOCKET NO. 7310." Retrieved September 27th, 2016, from http://files.hawaii.gov/dcca/dca/dno/dno2008/24086.pdf.

average on-peak avoided cost of electricity acts as a proper price signal to allow rooftop solar, utility scale solar and fossil fuel generation to compete to produce the lowest cost electricity for Hawaii.[236]

Alberta has a different method of determining the value of electricity as compared to Hawaii. The lessons from Hawaii can be applied to Alberta if the differences between the jurisdictions are considered. Since Hawaii is regulated using cost of service, the value of electricity is based on costs. The value of electricity produced by a rooftop solar panel is based on the generator costs it offsets. In Alberta the value of electricity is set in the power pool. Using the same logic that is used in Hawaii, rooftop solar customers should be reimbursed based on the wholesale price of electricity. The wholesale price of electricity is the value of electricity in Alberta. Rooftop solar customers should be reimbursed for excess production at the same rate that other generators are reimbursed for production. Hawaii's ruling on excess solar production supports the recommendation made in this paper to reimburse solar customers with the wholesale price of electricity.

16.3 Alberta's Distributed Generation Review

[236] Hawaii Public Utilities Commission (2015). "DECISION AND ORDER NO. 33258 ". Retrieved September 12th, 2016, from http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15J13B15422F9046418+A15J13B31859H489831+14+1960.

The Alberta Utilities Commission has conducted a review of the enablers and barriers to adopting distributed generation in the province. The review is intended to assist the provincial government to develop policy to support its goals of developing renewable energy and it includes studying the current transmission and distribution tariffs in the province. The commission provided the final report on their findings to the minister in December 2017.[237] The Minister of Energy will determine when the report released to the public. The report has not yet been released.

In future rate hearings, the commission will either choose to maintain the current rate structure or opt to update it. Any increases in fixed charges for transmission will come closer to setting the energy charge at the long-run marginal cost of transmission. Setting a 100% fixed charge is also not optimal because it underestimates the long-run marginal cost of transmission. The paper shows that there is an optimal level for the transmission energy charge and it sits somewhere below the current charge and above zero. If the long-run marginal cost of transmission in Alberta is the same as in Colorado, then the transmission rate should be set at 0.45 cents/kWh. Determining the long-run marginal cost of transmission for Alberta is essential to redesigning Alberta's residential transmission tariffs.

The current energy charge for distribution is closer to the long-run marginal cost of distribution than the current transmission charge is to the long-run marginal cost of transmission. An updated

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[237] Alberta Utilities Commission (2017). "Distributed generation review." Retrieved September 28th, 2017, from http://www.auc.ab.ca/regulatory_documents/Pages/Distributed-generation-review.aspx.

distribution charge in Alberta could either confirm that Alberta's distribution charge sits at the long-run marginal cost of distribution or update it to bring it closer to the long-run marginal cost of distribution. A specific study on Alberta would need to be carried out to determine the long-run marginal cost of transmission and distribution in Alberta.

Chapter 17 Conclusion

Alberta will see growth in rooftop solar over the next thirteen years. This paper forecasts that Alberta could have between 2965 MW and 5878 MW rooftop solar capacity by 2030 if solar customer follow the economic incentive to install solar. The actual penetration of rooftop solar will depend on the cost declines in rooftop solar technology, the electricity prices in the province and the discount rate of residential customers.

The problem with 2965 MW or 5878 MW of rooftop solar is that is the result of incorrect price signals. Residential customers are responding to the current transmission and distribution tariff structure and installing solar to offset their transmission and distribution costs. Alberta's residential transmission tariff does not reflect the long-run marginal cost of transmission. Alberta's current transmission tariff is greater than the long-run marginal cost of transmission and this leads to residential customers installing rooftop solar before the savings on the transmission grid justify the cost of the investment.

The transmission tariff would need to be a mix of a fixed and a variable charge for the tariff to be set at the long-run marginal cost of transmission. This is because transmission is a natural monopoly. Natural monopolies have decreasing average costs which means that the marginal cost must be below the average cost. If the price is set at the marginal cost and the marginal cost is below the average cost, then the firm will not recover all of its costs.

The second issue is that the reimbursement price that rooftop solar customers receive for excess generation put back onto the grid. The current price that solar customers receive for excess generation does not reflect the long-run marginal cost of electricity generation. This is problematic because it overstates the value of electricity produced by rooftop solar. The inflated reimbursement price for excess electricity incents rooftop solar adoptions to occur before rooftop solar is the lowest cost form of electricity generation in the province.

It is possible that Alberta's current residential distribution tariff is set at the long-run marginal cost of distribution. Studies from Colorado and California would suggest that Enmax and Epcor have distribution charges that are very close to the marginal cost of distribution and ATCO and Fortis have distribution charges that are higher than the long-run marginal cost of distribution. A study would need to be carried out that estimates the long-run marginal cost of distribution in Alberta. This would confirm whether Alberta's current residential distribution tariff needs to be updated.

When prices reflect the long-run marginal cost of the respective industry it ensures that customers are incented to choose the lowest cost goods in the market that provide the most value. In the electricity market it is important that transmission, distribution and electricity prices incent customers to choose the lowest cost forms of electricity that provide the most value to residential customers.

The inefficiency of 2965 MW or 5878 MW of rooftop solar is calculated by assuming the long-run marginal cost of transmission and distribution for Alberta. Studies from Colorado and

California that calculate the long-run marginal cost of transmission and distribution are applied to Alberta. If the long-run marginal cost of transmission and distribution in Alberta is equal to the cost estimates in the cited studies, the installation of 5878 MW of solar increases Alberta's electricity costs by 230 million dollars (2017 Canadian dollars) over 13 years. If the 2965MW solar forecast is used, the result is a 214 million dollars increase in electricity costs for Albertans. This is the result of residential customers using a higher cost form of electricity production than is necessary. Sourcing electricity from the grid would cost between 214 and 230 million dollars less than sourcing electricity from rooftop solar.

Alberta is still very early in its rooftop solar penetration. Examples from Arizona show that waiting to update tariffs after significant rooftop solar penetration can lead to legal battles. This can be avoided in Alberta if the transmission and reimbursement price are updated in the near future. With the hearing into distributed generation by the AUC completed, it is an excellent time to start the process of updating Alberta's residential transmission tariff and Alberta's reimbursement price for rooftop solar production.

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Appendix

The appendix includes all tables associated with the calculations made in the rooftop solar forecast. ATCO's 3rd quintile is used as the example for all tables.

Table 38 - ATCO's 3rd Quintile Solar Production and Consumption

	Quintiles				
Data inputs	1	2	3	4	5
Monthly kWhs consumed	244	392	508	646	1142
Capacity of Solar panels (kW)	2.5	4.0	5.1	6.5	11.6
Potential PV (annual kWh/kW)	1186	1186	1186	1186	1186
Average kWh produced per month	244	392	508	646	1142
Average kWh consumed from the grid	0	0	0	0	0

It is assumed in the forecast that all customers will install solar systems large enough to offset their electricity consumed over the course of one year. Table 39 provides these calculations. The monthly kWh consumed from Table 39 is then inputted into Table 40 to calculate the annual electricity charges facing solar and non-solar customers.

Table 39 - Annual Bill of ATCO Customer (3rd Quintile)

Column A	Column B	Column C	Column D	Column E	Column F	Column G	Column H	Column I
		Solar	non-solar					
	Monthly Consumption (kWh)	0	508					
Unit*	Transmission charge $/kWh	Distribution Charge (fixed) $/month	Distribution charge variable $/kWh	Administration Fee $/month	Local Access Fee $/ month	Energy Cost $/month	Annual Electricity cost (Grid Electricity) $/year	Annual Electricity Cost (Grid electricity supplemented with solar) $/year
2017	0.035	29.8	0.1	10	5	22	1417	530
2018	0.037	30.8	0.1	10	5	30	1543	543
2019	0.037	31.8	0.1	10	5	30	1573	556
2020	0.037	32.9	0.1	10	5	37	1681	571
2021	0.037	33.7	0.1	10	5	40	1747	582
2022	0.038	34.8	0.1	10	5	53	1935	598
2023	0.039	35.9	0.1	10	5	55	1997	613
2024	0.039	37.1	0.1	10	5	55	2028	628
2025	0.040	38.0	0.1	10	5	52	2018	639
2026	0.040	39.2	0.1	11	5	57	2105	655
2027	0.039	40.4	0.1	11	5	57	2134	671
2028	0.039	41.6	0.1	11	5	57	2164	686
2029	0.039	42.8	0.1	11	5	57	2195	702
2030	0.039	44.0	0.1	11	5	57	2225	718
2031	0.038	45.5	0.1	11	5	57	2263	738
2032	0.038	46.8	0.1	11	5	57	2294	754
2033	0.038	48.0	0.1	11	5	57	2326	770
2034	0.037	49.5	0.1	11	5	57	2362	789
2035	0.037	51.0	0.1	12	5	57	2400	808
2036	0.037	52.5	0.1	12	5	57	2439	828
2037	0.037	54.1	0.1	12	5	57	2482	849
2038	0.037	55.8	0.1	12	5	57	2525	870
2039	0.037	57.5	0.1	12	5	57	2571	892
2040	0.037	59.2	0.1	12	5	57	2617	914
2041	0.037	61.0	0.1	12	5	57	2665	938
2042	0.037	62.8	0.1	12	5	57	2714	961
2043	0.037	64.8	0.1	13	5	57	2765	986
2044	0.037	66.7	0.1	13	5	57	2817	1011
2045	0.037	68.7	0.2	13	5	57	2871	1037
2046	0.038	70.8	0.2	13	5	57	2926	1064
2047	0.038	73.0	0.2	13	5	57	2983	1091
2048	0.038	75.2	0.2	13	5	57	3041	1119
2049	0.038	77.5	0.2	13	5	57	3102	1148
2050	0.038	79.8	0.2	14	5	57	3164	1178
2051	0.038	82.2	0.2	14	5	57	3228	1209
2052	0.038	84.7	0.2	14	5	57	3294	1241
2053	0.038	87.3	0.2	14	5	57	3361	1273
2054	0.038	89.9	0.2	14	5	57	3431	1307
2055	0.038	92.6	0.2	14	5	57	3503	1342

Note: all values have been adjusted by a 2% inflation rate to set them at 2017 dollars. The PV calculation in Table 3 further adjusts these values using a real discount rate (6.6%).

Table 40 uses the monthly consumption value from Table 39 and the transmission, distribution, administration, local access fees and energy cost to calculate annual charges associated with consuming electricity with and without a solar panel.

The cost of solar is then taken from Table 41. Table 41 is the cost of solar reported by Kuby Renewables Ltd., adjusted upward by 10 percent to account for the different estimate by SunShot (see page 36 for details of calculation). For ATCO's 3rd quintile, the cost for the 5 kW system is used.

Table 40 - Solar Cost of Varying Solar Capacity Size

	kW of Solar Capacity													
$2017/kW	2	3	4	5	6	7	8	9	10	11	12	13	14	15
2017	4400	4180	3960	3575	3190	3080	2970	2860	2750	2640	2530	2420	2310	2200
2018	4253	4040	3828	3456	3083	2977	2871	2764	2658	2552	2445	2339	2233	2127
2019	4111	3905	3700	3340	2980	2878	2775	2672	2569	2467	2364	2261	2158	2055
2020	3974	3775	3576	3229	2881	2782	2682	2583	2483	2384	2285	2185	2086	1987
2021	3841	3649	3457	3121	2785	2689	2593	2497	2401	2305	2208	2112	2016	1920
2022	3713	3527	3341	3016	2692	2599	2506	2413	2320	2228	2135	2042	1949	1856
2023	3588	3409	3230	2916	2602	2512	2422	2333	2243	2153	2063	1974	1884	1794
2024	3469	3295	3122	2818	2515	2428	2341	2255	2168	2081	1994	1908	1821	1734
2025	3353	3185	3017	2724	2431	2347	2263	2179	2095	2012	1928	1844	1760	1676
2026	3241	3079	2917	2633	2350	2269	2187	2106	2025	1944	1863	1782	1701	1620
2027	3132	2976	2819	2545	2271	2193	2114	2036	1958	1879	1801	1723	1645	1566
2028	3028	2876	2725	2460	2195	2119	2044	1968	1892	1817	1741	1665	1590	1514
2029	2927	2780	2634	2378	2122	2049	1975	1902	1829	1756	1683	1610	1536	1463
2030	2829	2687	2546	2298	2051	1980	1910	1839	1768	1697	1627	1556	1485	1414

The cost from Table 41 is inputted into Table 42 under Column D. The kW of capacity is multiplied by the cost to calculate the total installation cost for each year of the forecast.

Table 41 – Present Value Calculation of ATCO Customers (3rd Quintile) with Current Tariffs

Column A	Column B	Column C	Column D	Column E	Column F	Column G
Year	Present Value of Electricity costs (grid option)*	Present Value of Electricity costs (grid supplemented with solar)*	Solar Panel Cost*	Present Value total Non-solar*	Present Value Total Solar*	Difference*
2017	$25,669	$8,505	$18,369	$25,669	$26,873	($1,205)
2018	$26,440	$8,709	$17,755	$26,440	$26,464	($24)
2019	$27,139	$8,918	$17,162	$27,139	$26,080	$1,059
2020	$27,863	$9,132	$16,589	$27,863	$25,721	$2,142
2021	$28,532	$9,350	$16,034	$28,532	$25,385	$3,147
2022	$29,185	$9,577	$15,499	$29,185	$25,075	$4,110
2023	$29,695	$9,808	$14,981	$29,695	$24,789	$4,906
2024	$30,185	$10,044	$14,480	$30,185	$24,524	$5,660
2025	$30,686	$10,286	$13,997	$30,686	$24,283	$6,404
2026	$31,245	$10,538	$13,529	$31,245	$24,067	$7,178
2027	$31,763	$10,797	$13,077	$31,763	$23,874	$7,889
2028	$32,296	$11,063	$12,640	$32,296	$23,703	$8,593
2029	$32,848	$11,337	$12,218	$32,848	$23,555	$9,293
2030	$33,419	$11,620	$11,810	$33,419	$23,430	$9,990
			* All costs are stated in 2017 Canadian Dollars			

The annual costs for grid and solar customers from Table 40 are used to calculate the present value of 25 year of electricity costs in Table 42. The first row in Column B is the present value of the annual electricity cost associated with staying on the grid from 2017 to 2041 (Column H in Table 40). The same calculation is done for solar costs in column C. The difference between solar and grid costs is then calculated in column G. If solar is cheaper over a 25 year time horizon, the customer can save money on electricity costs from installing solar.

Once the customer has an incentive to install solar, the customer the considers if they can save money by delaying the investment. Table 42 compares the benefit of waiting to install solar to the cost. Column A is the benefit associated with waiting one year to install solar. The benefit of waiting on year to install solar is that the cost of solar decreases (represented by ‘q’), the cost of installation is pushed out one year (represented by the discount rate ‘r’) and the customer can earn another year of earnings at the end of the delayed solar investment, discounted back to the current period (Profit(x+25) / (1+r)^25/ K(x)). See Equation 26 for how this term was derived. Column B shows the cost of waiting. Column B is the profit that the customer foregoes in the first year as a result of delaying the solar investment. If Column A is greater than Column B then the benefit of waiting one year to install solar is greater than the cost. This is the case up until 2030. In 2030 the cost of installing solar one year later is greater than the benefit and ATCO’s 3rd quintile chooses to install solar as a result.

Table 42 - Comparing Benefit of Waiting to Install Solar to Cost (ATCO’s 3rd Quintile)

	Column A	Column B
	q + r + Profit(x+25) / (1+r)^(25) / K(x)	Profit(x)/K(x)
2017	11.9%	5%
2018	12.0%	6%
2019	12.1%	6%
2020	12.2%	7%
2021	12.3%	7%
2022	12.4%	9%
2023	12.5%	9%
2024	12.7%	10%
2025	12.8%	10%
2026	13.0%	11%
2027	13.1%	11%
2028	13.3%	12%
2029	13.5%	12%
2030	10.3%	12.8%

ATCO's 3rd quintile installs solar in 2030 because the cost of waiting one more year to install is greater than the benefit. Table 43 calculates the MW of solar that are installed in 2030 as a result of ATCO's 3rd quintile substituting.

Column A of Table 43 is the number of sites in ATCO's service area from 2017 to 2030. The 2017 value is sourced from the MSA and the rate of growth from 2017 to 2030 is sourced from the Alberta government.[238] Column B is the size of a solar system in ATCO's 3rd quintile (from Table 38). Column C is the number of site multiplied by the size of the solar systems. This is the total MW installed in each year of the forecast.

Table 43 – MW of Solar Installed in ATCO's 3rd Quintile

	Column A	Column B	Column C
	Number of Sites in ATCO's 3rd Quintile	Size of Solar System in ATCO's 3rd Quintile (kW)	MW of Solar Installed in ATCO's 3rd Quintile
2017	30737	5.1	0
2018	31167	5.1	0
2019	31604	5.1	0
2020	32046	5.1	0
2021	32495	5.1	0
2022	32950	5.1	0
2023	33411	5.1	0
2024	33879	5.1	0
2025	34353	5.1	0
2026	34834	5.1	0
2027	35322	5.1	0
2028	35816	5.1	0
2029	36318	5.1	0
2030	36826	5.1	189

[238] Market Surveillance Administrator (2016). "2016-06-30 MSA Retail Market Statistics." Retrieved November 29th, 2016, from http://albertamsa.ca/uploads/pdf/Archive/0000-2016/2016-06-30_MSA_retail_market_statistics.xlsx.

Office of Statistics and Information - Demography (2017). "Population Projection Highlights." Retrieved August 28th, 2017, from http://finance.alberta.ca/aboutalberta/osi/demographics/Population-Projections/2017-2041-Alberta-Population-Projections-Highlights.pdf.

With the current transmission and distribution tariffs in place, ATCO's 3rd quintile installs 189 MW of solar in 2030. If the transmission and distribution tariffs were updated to reflect the long-run marginal cost of transmission and distribution, the amount of solar installed would decrease.

Table 44 compares the present value of the cost of using solar to the present value of the cost of using grid electricity over the 25 year investment period. The efficient tariffs are low enough that the incentive to install solar is lost for all years of the forecast.

Table 44 Present Value Calculation of ATCO Customers (3rd Quintile) with Efficient Tariffs

Column A	Column B	Column C	Column D	Column E
Year	Present Value total Non-solar*	Present Value Total Solar*	Difference*	MW of capacity installed (MW)
2017	$17,042	$26,873	($9,831)	0
2018	$17,616	$26,464	($8,848)	0
2019	$18,121	$26,080	($7,959)	0
2020	$18,647	$25,721	($7,074)	0
2021	$19,114	$25,385	($6,270)	0
2022	$19,560	$25,075	($5,516)	0
2023	$19,856	$24,789	($4,933)	0
2024	$20,135	$24,524	($4,390)	0
2025	$20,421	$24,283	($3,861)	0
2026	$20,758	$24,067	($3,309)	0
2027	$21,049	$23,874	($2,825)	0
2028	$21,348	$23,703	($2,356)	0
2029	$21,656	$23,555	($1,899)	0
2030	$21,974	$23,430	($1,456)	0
* All costs are stated in 2017 Canadian Dollars				

Table 44 shows that the solar adoption in Table 43 is inefficient. The efficient adoption is the adoption that was incented by transmission and distribution tariffs set at the long-run marginal cost of transmission and distribution. Any solar adoption above that level is above what is stated in Table 44 is too much.

Table 45 calculates the monetary value of the inefficiency of solar adoption. The monetary value of the inefficiency is the additional electricity costs that consumers spend as a result of the inefficient transmission and distribution. In the case of ATCO's 3rd quintile, the additional costs associated with using solar in 2030 is the value of the inefficiency.

The cost difference over the 25 year investment between solar and grid electricity is already provided in Table 44. This is the cost difference between solar and grid electricity over the life of the solar investment. Using the efficient transmission and distribution tariffs, solar is a higher cost form of electricity production compared to grid electricity for all years of the forecast. In 2030, the present value of the cost difference between solar and non-solar over the 25 years of the investment is $1456 (see Table 44). $1456 is multiplied by the number of customers in ATCO's 3rd quintile in Table 45 to calculate the value of the inefficiency in that year.

Table 45 - Inefficiency of ATCO's 3rd Quintile

Column A	Column B	Column C	Column D	Column E	Column F
Year	Substitution with current tariff (MW)	Substitution with efficient tariffs (MW)	Present Value of difference between solar and non-solar electricity using efficient tariffs (2017 dollars)	Number of Sites substituting to Solar in 4th Quintile in each year	Total Cost (Column D * Column E) - 2017 dollars)
2017	0	0	($9,831)	0	$0
2018	0	0	($8,848)	0	$0
2019	0	0	($7,959)	0	$0
2020	0	0	($7,074)	0	$0
2021	0	0	($6,270)	0	$0
2022	0	0	($5,516)	0	$0
2023	0	0	($4,933)	0	$0
2024	0	0	($4,390)	0	$0
2025	0	0	($3,861)	0	$0
2026	0	0	($3,309)	0	$0
2027	0	0	($2,825)	0	$0
2028	0	0	($2,356)	0	$0
2029	0	0	($1,899)	0	$0
2030	189	0	($1,456)	36826	$53,606,920
				Present Value	$23,304,653
				Real Interest Rate	6.6%

In 2030, 36,862 ATCO customers substitute to solar. This results in $53,606,920 in additional electricity costs over the 25 year investment compared to if the same electricity had been produced on the grid. $53,606,920 discounted back 13 years results in $23,304,653 in 2017 dollars ($53,606,920/(1.0662)^13=$23,304,653). This is the present value of the inefficiency of ATCO's 3rd quintile substituting to solar in 2030.