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Republic of Armenia:
Power Sector Tariff Study

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Abbreviations

AMD	Armenian Dram currency
ANPP	Armenia Nuclear Power Plant
CCGT	Combined Cycle Gas Turbine
CIS	Commonwealth of Independent States
CWIP	Construction Work in Progress
EE	Energy Efficiency
ENA	Electricity Network Armenia
EPMC	Equal Percentage of Marginal Cost
FB	Family Benefit program
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
HPP	Hydropower Plant
HVEN	High Voltage Electric Networks
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
kV	kilovolts
kWh	Kilowatt hour
MW	Megawatt
PFBP	Poverty Family Benefit Program
PSRC	Public Services Regulatory Commission
RE	Renewable Energy
R2E2	Renewable Energy and Energy Efficiency Fund
RR	Revenue Requirement
tcm	Thousand cubic meter
TPP	Thermal Power Plant
VAT	Value-added tax
WACC	Weighted Average Cost of Capital

Executive Summary

Armenia has a strong regulatory track-record in the power sector…

Regulatory reform underlies many achievements in Armenia's power sector. A strong regulatory framework, which includes a long-standing commitment to cost-recovery tariffs, has attracted substantial private sector participation to the sector. As a result, reliability, service quality and the efficiency of sector operations improved.

In recent years, however, increasing cost of electricity service and the Government's concern about affordability has led to a departure from cost-recovery tariffs.

… but, in recent years, tariff increases have not kept pace with rising costs

A combination of factors has led to rising costs per kWh of electricity consumption. The cost of natural gas accounts on average for 8-10 percent of the cost of service, and will likely increase as the import price of natural gas from Russia continues to rise. Moreover, as a result of the global financial crisis, the Armenian dram depreciated against the US dollar by 30 percent. The depreciation proved costly for many companies, particularly thermal power plants (TPPs), because gas payments and some debt service are denominated in US dollars. The crisis also affected consumption, which fell 7.4 percent in 2009. The drop in consumption increased the average cost of electricity per kWh as fixed costs had to be spread over fewer kWh of sales.

The Government tried to maintain affordable tariffs, however, some measures have hurt financial performance of the sector

The Government has taken steps to mitigate increases in the cost of service in order to maintain affordability. Some actions have benefited consumers without harming the financial sustainability of the sector. The gas-electricity swap with Iran has allowed Armenia to take advantage of excess capacity during off-peak hours and trade this for natural gas, which is needed to run the more expensive TPPs to meet peak demand.

Other government measures, however, have sought to maintain affordability at the expense of the financial sustainability of state-owned power companies, including:

- Under-recovery of capital costs for state-owned plants. The Government has waived the depreciation charge and return on assets for state-owned power companies
- Lack of adjustment for inflation. The allowance for wages, material, repair, and various other costs in each company's tariff has remained constant since 2009, despite 19 percent cumulative inflation over that period.
- Under-recovery of decommissioning charges. The tariff for the Armenia Nuclear Power Plant (ANPP) does not adequately cover the cost of decommissioning.

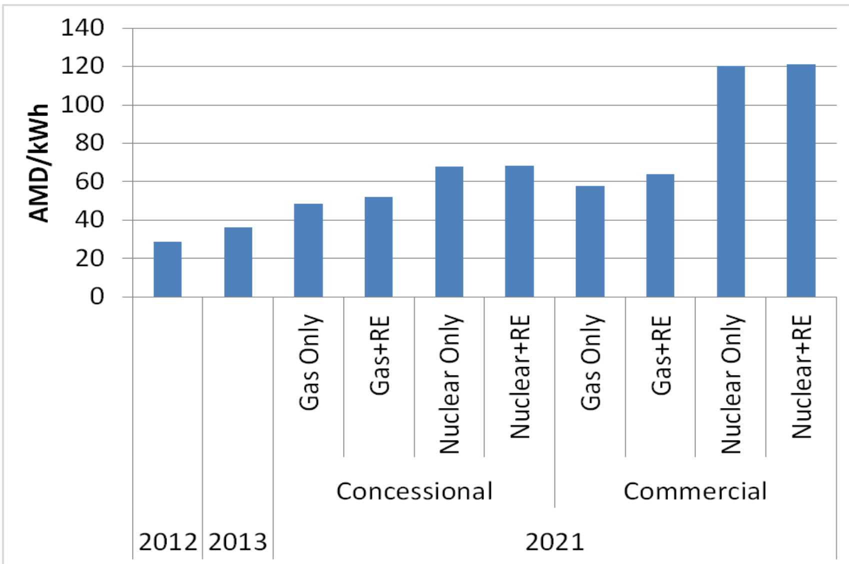
Average residential tariffs, equal to AMD 28.8/kWh or US$0.074/ kWh, are roughly 13 percent below the efficient cost of service as result of the above measures.

Large investments are needed in the sector, which will significantly increase revenue requirements

Armenia needs a large baseload plant by 2021 to replace the ANPP and two old gas-fired TPPs, Hrazdan TPP and Yerevan TPP, when they are retired. The Government plans to build a new 1,100 MW nuclear plant, but has yet to mobilize financing for the plant. Plans to tap into Armenia's renewable energy resources, including small- and medium-sized hydropower plants (HPPs), wind, and geothermal, can help to fill the gap, but will not be sufficient to replace the ANPP. The only other viable baseload alternative for Armenia would be a large, gas-fired TPP. Ongoing investment is also needed to rehabilitate Armenia's aging transmission and distribution networks. Thus, beginning in 2021, roughly AMD 78-373 billion (1-5 percent of estimated 2021 GDP) will be needed in additional sector revenue annually to cover the cost of supply. The share of generation in total sector revenue will increase from roughly 60 percent in 2012 to 75-90 percent in 2021 as a result of the required investments.

Large tariff increases will be needed to finance those investments

Large tariff increases will be needed to cover the revenue requirement with new investments. To allow for full cost-recovery, end-user tariffs would need to increase 70–270 percent depending on the investment scenario, with the largest increase expected if a new nuclear plus some renewable energy plants are constructed with commercial financing. The figure below shows 2021 marginal cost-based tariff levels under the different investment scenarios.



The tariff structure is suboptimal

The tariff structure does not reflect the marginal cost of serving different customer classes. This provides distorted price signals to customers, leading to inefficient consumption, particularly during high cost winter peak hours when Armenia's expensive TPPs must operate to meet demand. Presented below are the deviations from marginal cost based tariff setting principles:

- **Seasonality.** Armenia does not have a seasonal tariff, despite the fact that winter marginal costs are significantly higher than summer marginal costs.
- **Time of use.** The differential between peak and off-peak, or day and night, tariffs does not reflect the difference in the marginal cost of service during those two periods.
- **Fixed charges.** Armenia does not have a fixed component in the monthly bill despite the fact that there are significant customer-related (and demand-related) costs of service, which are not driven by kWh consumed.
- **Voltage levels.** Allocation of revenue to different customer classes does not reflect the differences in the marginal cost of serving different voltage levels. As a result, non-residential customers have cross-subsidized residential consumption.

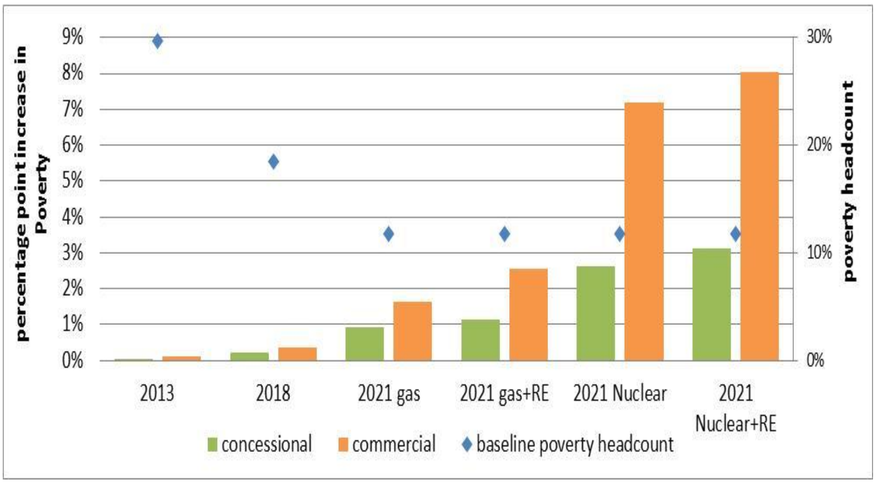
Marginal cost-based tariffs will improve efficiency

A marginal cost-based tariff structure would include a seasonal component and fixed component to better reflect how incremental costs are incurred. It would also improve the revenue allocation to customer classes to remove existing cross-subsidies and contribute to increased energy efficiency. The table below compares the existing end-user tariff structure to the marginal cost-based proposed tariff structure.

	Residential	0.4 kV	6 (10) kV	35+ kV
Current Tariff	(AMD/kWh)			
Day	30	30	25	21
Night	20	20	17	17
Marginal Cost-Based Tariff	(AMD/customer/month)			
Monthly Marginal Customer-Related Cost	2,551	7,365	120,805	718,610
Combined Marginal Energy and Capacity Costs	(AMD/kWh)			
Winter peak	35.8	35.8	34	23.2
Winter off-peak	9.7	9.7	9.4	8.8
Summer peak	5.2	5.2	5	4.7
Summer off-peak	2.9	2.9	2.8	2.6

Many households will struggle to pay electricity bills if the critical investments are made

Many households will struggle to afford electricity at tariffs that cover the cost of new generation and reflect marginal costs. Tariff hikes could result in 1–8 percent increase in poverty compared to the baseline for 2021.[1] Electricity poverty would increase 2–5 percent depending on the investment scenario, with a heavier burden on the poorest households. Armenia's targeted social assistance program, known as the Poverty Family Benefit Program (PFBP), helps to reduce poverty among vulnerable households. However, current allocations under the PFBP would not be sufficient to protect its beneficiaries from poverty. The figure below shows the increases in poverty levels as a result of the tariff increase for FB and non-FB beneficiaries.



Transition mechanisms can cushion the sudden impact of tariff increases

The PSRC can reduce the sudden impact of tariff increases by employing mechanisms to help transition to marginal cost-based tariffs. These transition mechanisms could include:

- **Regulatory accounting methods to smooth out the increase in the revenue requirement.** New investments can cause a large one-time increase in the revenue requirement. However, regulatory mechanisms, such as Construction Works in Progress (CWIP) or creation of a regulatory asset can be used to help "smooth out" the increase in the revenue requirement over several years in order to avoid rate shock. The figure below shows how CWIP would help smooth out the increase in average tariffs for one of the generation scenarios.
- **Modified approach to revenue allocation.** In developing a marginal cost-based tariff, economic efficiency requires recovery of costs from, or allocation of revenue to, customers in proportion to their marginal cost revenues.[2] Residential

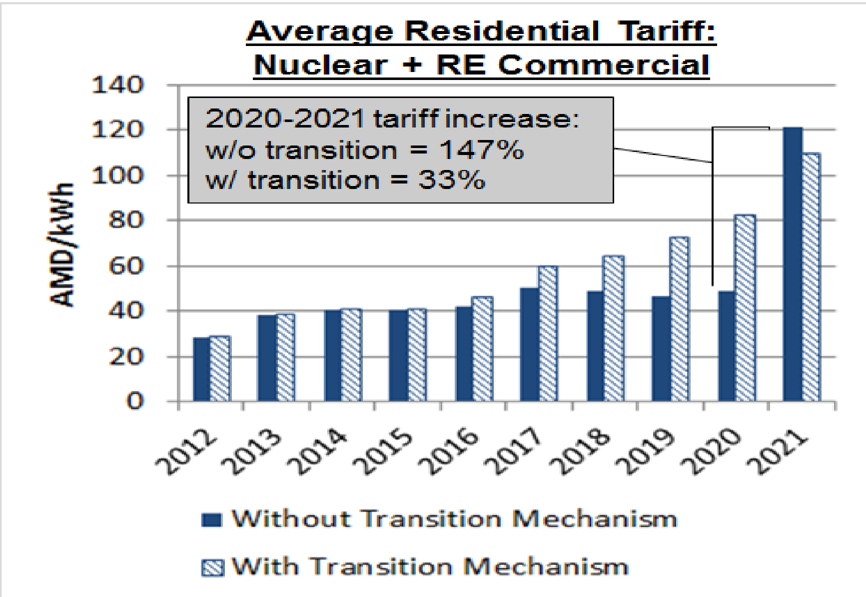
[1] Baseline poverty incidence is the poverty incidence that would be expected in 2021 if tariffs remain at constant 2010 prices.

[2] "Marginal cost revenues" are the sum of the marginal generation, transmission, and distribution costs associated with serving an additional kWh of energy, kW of demand, or customer, multiplied by the class' kWh, kW and number of customers.

customers tend to account for a significant portion of some cost categories, for example, customer-related costs. Allocating these costs to customers in proportion to their contribution to marginal costs can impose excessive hardship on one customer class if a marginal cost-based approach to revenue allocation has not been used in the past. However, transitional mechanisms can be used that preserve some of the important price signals of marginal costs, but reduce the burden on one class.

- **Transition to marginal cost-based differences in tariff components.** A marginal cost-based tariff structure should be established immediately in order to allow customers time to understand and therefore react to price signals. However, introduction of a marginal cost-based tariff structure can cause large bill impacts for some customers. Once the recommended tariff structure is established, transition steps can be taken to adjust the differential between costing periods over time to eventually reflect differences in marginal costs by period.

The figure below shows how the regulatory accounting mechanism, construction work in progress, can help smooth out the tariff increase.



In some cases, an unsustainably large single-year tariff increase is expected even when these regulatory mechanism are in place. When this occurs, the Government may choose to make a policy decision to cap tariff increases for the entire residential population and cover the revenue gap with a transitional subsidy. This transitional subsidy can be phased out over time, but should be considered as a mechanism of last resort because it has high fiscal costs and tends to disproportionately benefit portions of the population that can afford larger tariff increases.

Social impact mitigation measures will be needed to preserve affordability in all investment scenarios

Electricity tariffs will remain unaffordable for a portion of the population even with a transition plan to gradually approach marginal cost-based tariffs. The Government will need to strengthen the social mitigation mechanisms to help ensure electricity affordability for poor households. Options for delivering a subsidy to poor households include:

- **Reduced tariff for all customers**. The Government could transfer funds directly to sector companies in order to reduce the revenue requirement to be recovered through tariffs.
- **Lifeline tariffs**. Lifeline tariffs could be used to ensure lower tariffs for certain customers based on the amount of household consumption. These tariffs could be applied to the initial block of consumption, called the basic need level.
- **Cash transfer to households.** Cash transfers are a mechanism by which the Government could increase consumers' purchasing power by supplementing the household income with money allocation, which may be intended for a particular purpose, but are not required to be used in that way.
- **Voucher program.** Voucher schemes, or near-cash transfers to households, also aim to increase consumers' purchasing power; however, unlike cash, which can be used to buy anything, vouchers are designated for a specific purpose such as the purchase of electricity.

The Government could also help households consume less electricity, and thereby reduce their electricity bills, by promoting energy efficiency. For example, the Government could provide a subsidy to households for purchasing energy efficient equipment or to carry out a home energy audit.

	Economic Distortion	Fiscal Costs	Coverage		Targeting	
	Rank[3]	bln AMD	NP	P	NP	P
Voucher Program/Cash Transfer to All Poor Households	1	1.5-14.5	0%	98%	0%	100%
Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries	3	1.4-3.6	8%	43%	55%	45%
Lifeline tariffs - Increasing Block Tariff for FB beneficiaries	5	1.4-3.3	8%	43%	55%	45%
Voucher Program/Cash Transfer to FB beneficiaries	1	1.6-14.8	8%	43%	60%	40%
Lifeline tariffs - Increasing Block Tariff for all customers	6	12.3-75.7	98%	98%	88%	12%
Lifeline tariffs - Volume Differentiated Tariff for all customers	4	2.7- 60.8	17%	34%	82%	18%
Reduced tariff for all customers	7	24-147	99%	98%	90%	10%

P=Poor NP=Non-Poor

[3] 1=Least distortionary; 7=Most distortionary.

1 Introduction

Armenia's energy sector has achieved a level of electricity reliability, service quality and efficiency of sector operations that stands out among countries participating in Commonwealth of Independent States (CIS). Much of this can be attributed to a decade of regulatory reform including a long-standing commitment to cost-recovery tariffs.

In recent years, however, increasing cost of electricity service provision and Government concern about affordability has led to a departure from cost-recovery tariffs. Going forward, balancing the competing objectives of maintaining affordability and preserving the financial sustainability of the sector will become more challenging as significant investments are needed to replace aging generation, transmission, and distribution infrastructure.

Electricity tariffs play a central role in this challenge. Understanding how far tariffs have fallen below cost-recovery levels and how much they will need to increase to cover the costs of new investments can help policymakers make informed decisions on investments needed in the energy sector and social assistance that may be needed to protect the poor as tariffs increase to cover these investments. Updating the tariff structure to reflect existing consumption and cost patterns can improve price signals, thus, increasing end-use efficiency.

This study aims to present analysis that provides insight on these issues. The intention of the study is not to recommend a specific level for the tariff in Armenia, but to demonstrate the possible impact of new investments on the tariff and outline the key features of a more efficient tariff structure.

The study is structured as follows:

- Section 1 provides definitions of the key terms used and a background on the current tariff setting process in Armenia
- Section 2 indicates how far tariffs have departed from cost-recovery levels and what costs have not been covered as a result
- Section 3 describes how new investments will affect the average cost of service and the average residential tariff
- Section 4 proposes a marginal cost-based tariff structure and explains why this differs from the current tariff structure
- Section 5 discusses the poverty and social impact of tariff increases needed to cover new investments in 2021
- Section 6 identifies options for subsidization and mitigating rate shock that will help transition to higher, marginal cost-based tariffs
- Section 7 summarizes conclusions and recommendations of the analysis.

1.1 Definition of Key Terms

This study uses a number of terms that are specific to or have specific definitions when used in the context of economic regulation in the electricity sector. Table 1.1 provides definitions of these key terms.

Table 1.1: Definition of Key Terms

Term	Definition
Average end-user tariff	The average of tariffs for all customer classes weighted by consumption
Average cost of service	The sum of all costs allowed by the regulator divided by consumption
Efficient cost of service	The fair and reasonable operations and maintenance (O&M) and capital cost of providing reliable electricity service
Cost-recovery tariff	An end-user tariff (or tariffs) that fully covers the efficient cost of service of all utilities in the power system
Revenue requirement	The revenue required to cover the efficient cost of service for a single company or for the power system as a whole
Energy costs	Costs that vary with each unit of energy (kWh) generated; These costs are also considered variable costs
Capacity costs	Costs that are incurred with each unit of demand (kW) for capacity; These costs are generally considered fixed in the short-run, but variable in the long-run
Customer-related costs	Costs that are incurred based on the number and location of customers; These costs are considered fixed costs
Customer class	A group of customers with similar consumption patterns and characteristics. This classification is used to design tariffs for different types of customers. In Armenia, customer classes are differentiated by voltage level
Class revenue allocation or class allocation	The process of determining how much of the revenue requirement should be collected from each customer class
Marginal cost revenue	The revenue that would be collected if tariffs were set equal to marginal costs. This is not necessarily equal to the revenue required to cover the efficient cost of service

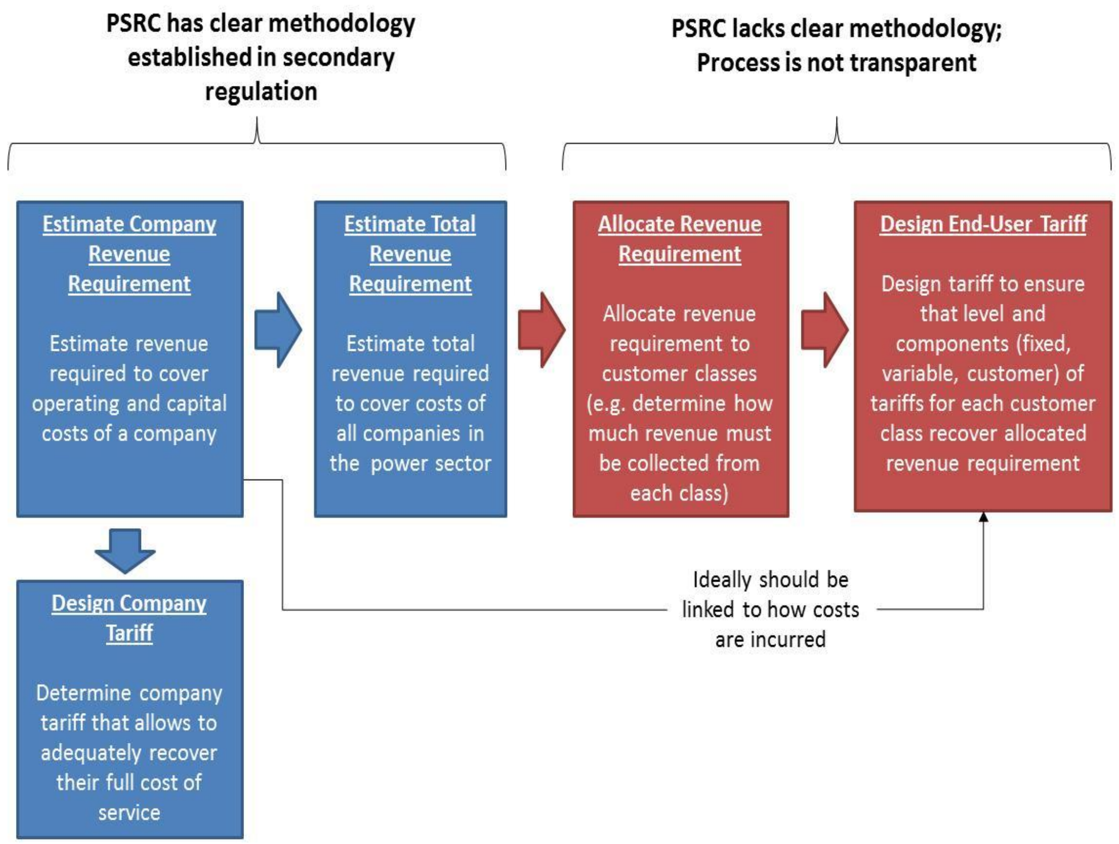
1.2 Overview of Regulatory Framework for Tariff Setting

The Public Services Regulatory Commission (PSRC) is responsible for setting tariffs in the electricity sector. The PSRC has clear methodology for setting tariffs for all companies in the sector. It does not, however, have a clear methodology for determining how much revenue should be accrued from each customer class or for determining the end-user tariff structure and rates within each class that will achieve the class revenue.

This is an important missing link in the tariff setting process in Armenia. Without a clear methodology for determining how much revenue should be collected from each class, the PSRC has no way to track whether or not cross-subsidies exist between customer classes. The PSRC also lacks a methodology for determining how revenue should be accrued through different components of the tariff. For example, during the last tariff increase, both day and night tariffs increased by 5 AMD/kWh without consideration of whether more of the increase should occur during daytime hours when higher costs tend to be incurred by companies.

Moreover, since tariffs have not increased in Armenia since 2009, the PSRC has had to work to "fit" the revenue required to operate the sector so as to match the revenue collected from customers. Some difference between the revenue requirement for the sector and the revenue from customers is to be expected every year because of uncertainty in demand, supply availability and costs. This discrepancy must then be adjusted or "trued-up" in the following year to ensure that companies receive their required revenue and customers are not overcharged for service. However, the lack of increases in end-user tariffs in recent years coupled with cost increases driven by higher natural gas prices, inflation and a large drop in demand in 2009 led to a mismatch in the revenue collected from customers and the revenue required to cover the efficient cost of electricity service. Figure 1.1 illustrates the steps in the tariff setting process and indicates where the PSRC lacks a clear tariff setting methodology.

Figure 1.1: Tariff Setting Process



Source: Bank team.

The following subsections describe how tariffs are set for individual companies in the sector and the current class allocation and tariff structure for end-users.

1.2.1 Tariffs for Individual Companies

The PSRC process for setting tariffs for individual companies has three steps:

- **Establish company revenue requirement.** The PSRC establishes the revenue requirement in consultation with the company.
- **Classify costs.** The PSRC classifies costs into two categories: fixed and variable. If a single-part tariff structure is used for the company (as is the case for transmission and distribution and some generation companies), no cost classification is required.
- **Determine company's tariff structure.** The PSRC establishes the tariff structure in consultation with the company. This structure varies by entity and generally reflects how the company's costs are incurred.

The following describes each of these aspects of tariff setting in further detail.

Establishing the Revenue Requirement for Individual Companies

The PSRC uses what is commonly referred to as "rate-of-return" regulation to calculate the revenue requirement for power sector companies. The revenue requirement (RR) under rate-of-return regulation is calculated as follows:

$$RR = AC + D + AP * r$$

AC – allowed annual costs, including operations and maintenance costs

D – annual depreciation of fixed assets

AP – rate base

r – allowed rate of return

The components that make up the revenue requirement include:

- **Allowed costs.** These are fuel costs, non-fuel operations and maintenance (O&M) costs, administrative and general costs such as salaries and rent, taxes, and, for the distribution company, a provision for bad debt.
- **Depreciation expense.** Depreciation is a non-cash expense but regulators typically allow it to be recovered through tariffs so that energy companies have some funds with which to renew or replace old assets.
- **Rate base**. The rate base is the value of assets on which a company is allowed to earn a return or profit.[4] The rate base is the sum of the following:
  - The residual value of the assets;
  - Near-term investments expected to be included in the rate base;
  - An allowance for working capital.

[4] The term "profit" is used throughout this report to mean the allowed return on assets recovered through the tariff.

- **Costs of debt and equity**. The costs of debt and equity determine the return the energy companies are allowed to earn on their rate bases. This is determined by the following:
  - The respective costs of debt and equity allowed by the PSRC;
  - The mix of debt and equity financing used.

In certain cases, the PSRC uses a "cash needs" approach for calculating the revenue required to cover debt service for specific large investments financed on concessional terms. When this approach is taken, investments financed from concessional loans are recovered through an annual debt service charge and not included in the rate base. For example, a rate base is not used in estimates of the revenue requirement for Yerevan CCGT because the plant has been 100 percent financed with a concessional loan from the Japanese Government and capital costs are therefore recovered through an explicit debt service charge.

Cost Classification

Costs for generation companies that have a two-part tariff structure are grouped into two categories to determine how much of the revenue requirement should be recovered from each component of the tariff. The PSRC groups costs as follows:

- **Variable costs** are costs that vary depending on the amount of electricity generated. These include fuel costs (at thermal and nuclear plants), a portion of repair costs, the portion of the company's allowed profit that covers return on equity and income tax, and, in some cases, a portion of payroll costs and a portion of depreciation costs.
- **Fixed costs** are costs that are incurred regardless of how much power is produced. These include the cost of maintaining fixed assets, depreciation costs, and the portion of allowed profit that is required to service debt.

Companies must submit and agree upon their principles of cost classification with the PSRC. In some cases, the PSRC may allow a deviation from the above classification of costs. For example, in 2012 the PSRC allowed all costs at Hrazdan 5 to be classified as variable because the company operated in testing mode for part of the year.

Tariff Structure of Power Sector Companies

The PSRC has different methodologies for setting the tariff structure for companies in each power subsector. These methodologies are briefly shown in Box 1.1. Box 1.2 describes the process for setting feed-in tariffs for renewable energy technologies, which is slightly different than for other companies in the sector.

Box 1.1: Tariff Methodologies for Generation, Transmission and Distribution

Generation

$$One - Part\ Tariff = \frac{RR}{Net\ Generation}$$

$$Two - Part\ Tariff = \frac{VC}{Net\ Generation}\ \&\ \frac{FC}{\substack{Monthly\ Contracted \\ Available\ Capacity}}$$

Where:

RR – revenue requirement
VC – variable costs
FC – fixed costs

Transmission

$$Transmission\ Tariff = \frac{RR}{Wc + We}$$

Where:

RR – revenue requirement
Wc – electricity transmitted domestically
We – electricity exported under contracts (or as approved by the PSRC)

Distribution

$$Distribution\ Tariff\ Margin = \frac{RR}{C} - T$$

Where:

RR – revenue requirement
C – electricity sold to end-users
T – weighted average tariff of purchased electricity

Settlement and System Operations

$$FMP = \frac{Wi}{Wi + We}\ x\ \frac{RR}{12}$$

$$Te = \frac{RR}{Wi + We}$$

Where:

FMP – fixed monthly payment charged for services to the domestic wholesale market (AMD/month)
Te – tariff for servicing 1 kWh of exported electricity (AMD/kWh)
RR – revenue requirement
Wi – electricity bought for domestic consumption
We – electricity exported under contracts (or as approved by the PSRC) (kWh)
We – weighted average tariff of purchased electricity

Source: PSRC

Box 1.2: Feed-In Tariff Methodology for Renewable Energy Generation

In 2007, the PSRC issued a resolution to set the following feed-in tariffs (before value added tax) for generation from renewable energy sources:

- AMD 18.274 /kWh for Small HPPs constructed on natural flows
- AMD 12.182 /kWh for Small HPPs constructed on irrigation systems
- AMD 8.122 /kWh for Small HPPs constructed on drinking water pipelines
- AMD 35 /kWh for Wind Plants
- AMD 35 /kWh for Power Plants operating on biomass.[5]

Of these renewable energy generation sources, Armenia currently generates from small HPPs, a 2.6 MW wind farm, and a biomass plant. In 2011, Armenia had 180 MW of small HPPs in operation which generated around 450 million kWh annually. 40 MW of additional capacity is expected to come online each year for the next four years, equivalent to 100 million kWh of additional generation annually.

The methodology for feed-in tariffs includes the following formula for adjusting tariffs to account for the impact of inflation and exchange rate fluctuations:

$$T = T_1 \left[k_1 \frac{PI}{100} + k_2 \frac{ER_1}{ER_2} + (1 - k_1 - k_2) \right]$$

in which,

T – the value of the set tariff (AMD/kWh);

T_1 – the value of the currently effective tariff (AMD/kWh);

k_1 – the portion of the currently effective tariff that is subject to adjustment to the rate of inflation and is accepted equal to 0.25;

PI – the consumer price index for the period of January-September of the current year over the same period of the previous year;

k_2 – the share of the current tariff that can be adjusted based on AMD/US$ exchange rate fluctuation; this share cannot exceed 35 percent of the tariff;

ER_1 – the average of AMD/US$ exchange rates during the period of January-September of the current year;

ER_1 – the average of AMD/US$ exchange rates during the period of January-September of the previous year.

Source: PSRC

End-Users

As mentioned above, the PSRC lacks a clear methodology for allocating revenue to customer classes and determining the structure and level of end-user tariffs in Armenia. The PSRC last changed end-user tariffs in April 2009. These are shown in

Table 1.2.

[5] Public Services Regulatory Commission. Resolution No. 207. Dated May 4, 2007. Yerevan, Armenia.

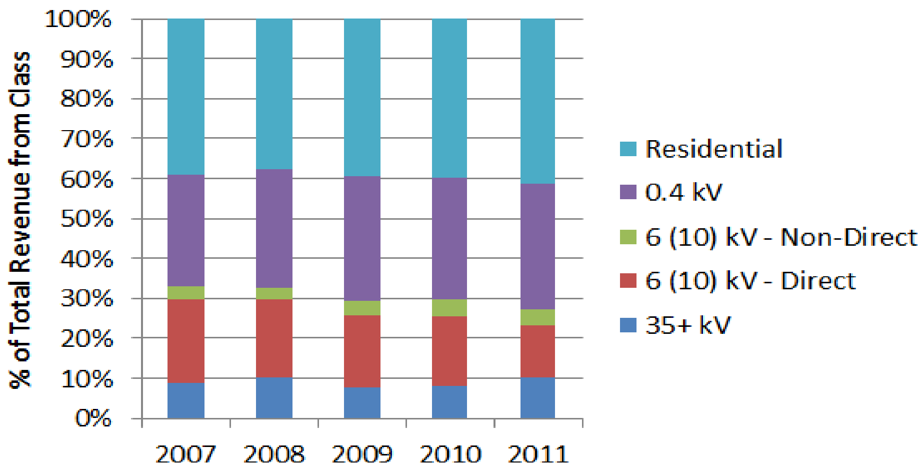
Table 1.2: End-User Tariffs, VAT inclusive

	Day	Night
	(AMD/kWh)	
Residential	30	20
0.4 kV	30	20
6 (10) kV – Non-Direct	30	17
6 (10) kV – Direct	25	17
35+ kV	21	17

Source: PSRC.

The revenue collected from each class has stayed stable over the past five years despite the lack of methodology for revenue allocation to classes. Figure 1.2 shows the percentage of total sector revenue collected from each customer class from 2007-2011.

Figure 1.2: Percentage of Revenue Collected from Each Customer Class, 2007-2011



Source: PSRC.

2 Cost-Recovery Tariffs: Short-Run

In recent years, increasing cost of electricity service provision and Government concern about affordability has led to a departure from cost-recovery tariffs.

A combination of factors has led to an increase in the cost of electricity service. The cost of natural gas represents 8-10 percent of the cost of serving end-users, and will likely increase as the import price of natural gas from Russia continues to rise. The import price of natural gas increased from US$110/ tcm) in 2008 to US$180/ tcm in 2011 and the Armenian dram depreciated against the US$ by 30 percent. The depreciation proved more costly for many companies, particularly thermal power plants (TPPs), because gas payments and some debt service are denominated in US dollars. The crisis also affected consumption, which fell 7.4 percent in 2009. The drop in consumption increased the average cost of electricity per kWh as fixed costs had to be spread over fewer kWh of consumption.

The Government has taken steps to mitigate increases in the cost of service in order to maintain affordability. Some actions have benefited consumers without harming the financial sustainability of the sector. The gas-electricity swap with Iran has allowed Armenia to take advantage of excess capacity during off-peak hours and trade this for natural gas, which is needed to run the more expensive TPPs to meet peak demand.[6] The swap in combination with two new efficient TPPs—Yerevan CCGT and Hrazdan 5—has been critical to reducing the impact of the rising costs on end-users.

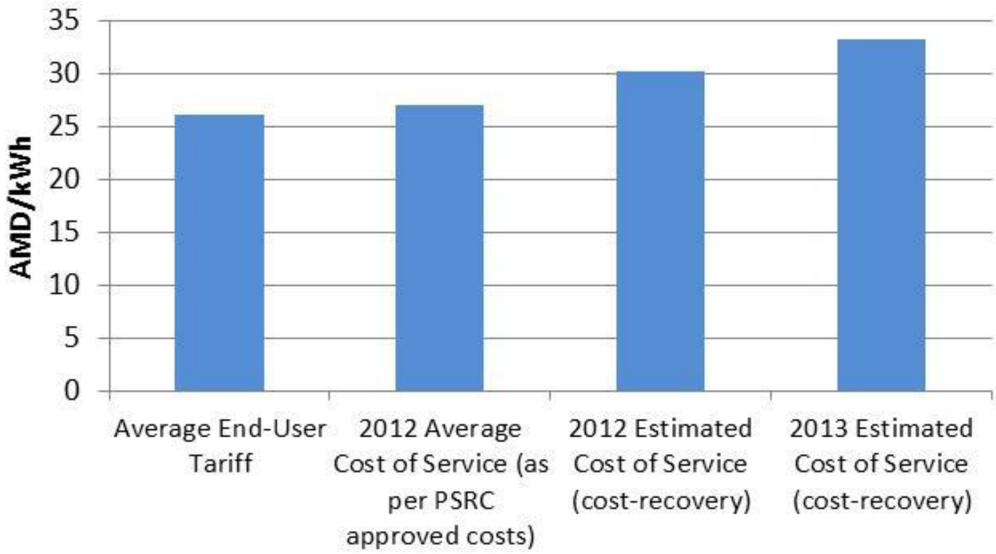
Despite these efforts, tariffs do not sufficiently cover the cost of service. Section 2.1 compares the average cost of service under existing generation, transmission, and distribution tariffs to the average cost of service when all efficient and reasonable costs are included. Section 2.2 explains how we have adjusted tariffs for individual companies to fully reflect their cost of service. Section 2.3 identifies other reasons why tariffs may not reflect the cost of service.

2.1 Average Cost of Service: Actual versus Cost-Recovery

In 2012, average end-user tariffs were 13 percent below cost-recovery levels. As a result, the sector had a shortfall of AMD 22 billion (US$ 57 million) in revenue. This represents roughly 16 percent of the total revenue required to cover the efficient cost of service. If tariffs do not increase in 2013, this sector revenue shortfall could reach AMD 36 billion (US$ 101 million) or roughly 25 percent of the total revenue requirement for the sector. Figure 2.1 compares the weighted average end-user tariff in 2012 to: (i) the average cost of service in 2012 based on the PSRC's tariffs for individual companies and projections of demand, (ii) tariffs for individual companies adjusted to cover their full cost of service, and (iii) the estimated average cost of service in 2013. Table 2.1 shows the sector revenue shortfall under each of these scenarios.

[6] Box 2.1 in Section 2.3 describes the benefits of the gas-electricity swap with Iran in further detail.

Figure 2.1: Average End-User Tariff v. Average Cost of Service under Different Scenarios



Source: Bank team estimates.

Table 2.1: Sector Revenue Shortfall resulting from Tariffs that are below Cost-Recovery

		Consumption	Sector Revenue Shortfall		
	AMD/kWh (VAT incl.)	*mln kWh*	*mln AMD*	*mln USD*	*% of Total Rev. Requirement*
Weighted Average End-User Tariff	26.19	5,566	---	---	---
2012 Average Cost of Service (actual)	27.04	5,566	4,691	12	4%
2012 Average Cost of Service (cost-recovery)	30.16	5,566	22,046	57	16%
2013 Estimated Cost of Service	33.23	5,692	39,169	101	25%

Source: Bank team estimates.

Tariffs are below cost-recovery levels for two reasons. First, the weighted average end-user tariff does not cover the average actual cost of service. The PSRC set new tariffs for individual companies in April 2012, but did not change end-user tariffs. As a result, end-user tariffs do not bring in sufficient revenue. This revenue shortfall disproportionately affects ENA. As the single buyer, ENA must pay other companies based on the tariffs set by the PSRC, but cannot bill end-users to sufficiently cover these costs. The difference is accounted for in a below cost recovery distribution margin.

Second, tariffs for individual companies do not reflect the efficient cost of service. Tariffs are below cost recovery levels for several reasons:

- The Government has waived the return on assets and depreciation components of the tariff for several state-owned companies;
- The return on assets does not include an allocation for working capital;
- Decommissioning costs for ANPP are too low.

Additionally, the tariff for ANPP will need to increase further in 2013 to begin recovering the cost of life extension until 2021. Table 2.2 shows actual versus cost-recovery tariffs for individual companies. Section 2.2 describes how we adjust tariffs for individual companies.

Table 2.2: Actual versus Cost-Recovery Tariffs for Individual Companies

Company	2012 Actual Tariff	2012 Cost-Recovery Tariff	2013 Cost-Recovery Tariff (est.)
	AMD/kWh		
Hrazdan TPP	41.219	41.227	40.92
Hrazdan 5	13.269	13.269	13.269
Yerevan CCGT	3.242	3.242	3.242
Vorotan Cascade of HPPs	4.778	7.049	7.621
Sevan-Hrazdan Cascade of HPPs	4.56	4.578	4.838
ANPP	9.658	14.109	16.995
Small HPPs	18.274	19.293	19.293
HVEN	0.3325	0.6517	0.5429
ENA	9.338	9.338	9.476
	Million AMD/month		
Settlement	9.0513	9.0513	9.0513
System Operations	93.9496	93.9496	93.9496

Source: PSRC and Bank team estimates.

2.2 Why Tariffs Do Not Cover the Cost of Service in the Short-Run

Tariffs for individual companies in the sector do not provide sufficient revenue to cover full cost of service. As shown in Table 2.2 we have made adjustments to the tariffs for several companies to reflect their full cost of service. The following subsections describe the main components of tariffs that do not cover costs.

Waived or Under-Recovery of Return on Assets

The Government waived a portion of the return on assets for two state-owned companies – Vorotan and HVEN. Specifically, the Government asked the PSRC to waive some or all of the depreciation and profit charges in the tariffs for these two companies. As a result, the companies lack necessary revenue to cover capital expenditure needed for ongoing rehabilitation of aging assets. This is particularly a concern given the age and condition of assets at both companies.

This study uses information provided by the PSRC to estimate the appropriate level of depreciation and profit components of the tariff for the two state-owned companies (see Appendix A). As Table 2.3 shows, waiving of depreciation and profit had a significant impact on the allowed revenue for these two companies. Adding the full amount of these two tariff components back into the tariff for HVEN and Vorotan increases the revenue requirement by 166 percent and 49 percent, respectively.

Table 2.3: Impact of Waiving Depreciation and Profit for State-Owned Companies

	Vorotan		**HVEN**	
	Actual	Adjusted	Actual	Adjusted
Depreciation	4657	4692	0	3732
Profit	0	2750	0	430
Other Expenses	957	957	2504	2504
Revenue Requirement	5614	8364	2504	6666
Tariff (excluding VAT)	4.778	7.118	0.3325	0.8851
% increase in Revenue Requirement	49%		166%	

Source: Bank team estimates.

The return on assets was also too low for some companies because of a lack of allocation for working capital.[7] As shown in Table 2.2, slight adjustments in the tariff for Sevan-Hrazdan HPP, Hrazdan TPP, ANPP, Vorotan, and HVEN were made to cover working capital.

Decommissioning and ANPP Life Extension

The Decommissioning Fund, which is intended to recover the costs of decommissioning prior to the retirement of the nuclear plant, is underfunded. Decommissioning is expected to cost around US$250 million.[8] Payment into the fund would need to increase from AMD 400 million (US$1 million) annually to AMD 9,733 million (US$24 million) to provide sufficient funds for decommissioning in 2021.

[7] The return allowed for working capital was estimated based on: i) annual operations and maintenance expenditure assuming a one-month lag in receivables and payables, and ii) material and supply expenses equal to 3 percent of the balance asset value.

[8] Based on decommissioning cost range estimated in: "Armenia Power Sector 2006 Least Cost Generation Plan." May 2006.

Additionally, continued operation of the ANPP beyond 2016 will require significant life extension investment. Life extension is expected to cost roughly US$212 million.[9] Annual revenue required to cover this investment, assuming costs are recovered beginning in 2013 until ANPP is retired in 2021, will equal roughly AMD 10,470 million (US$27 million).

Table 2.4 compares the current generation tariff for ANPP to a cost-recovery level generation tariff for ANPP that includes sufficient allocation of funds to the Decommissioning Fund and, beginning in 2013, the cost of investment in life extension activities.

Table 2.4: Current ANPP Tariff versus Tariff with Full Decommissioning and Life Extension Costs

	Units	Current Tariff (2012)	Tariff with Full Decommissioning Payment (2012)	Tariff with Full Decommissioning Payment + Life Extension Costs (2013)
Fuel expenses	mln AMD	9,597	9,597	9,597
Operations and Maintenance	mln AMD	6,523	6,523	6,523
Allocations to the Fuel Storage Fund	mln AMD	1,500	1,500	1,500
Allocations to Decommissioning Fund	mln AMD	400	9,733	9,733
Life Extension Investment Activity	mln AMD	---	---	10,469
Other Expenses	mln AMD	2,133	2,133	2,133
Total Production Expenses	mln AMD	20,153	29,486	29,486
Profit	mln AMD	100	100	100
ANPP Annual Revenue Requirement (w/o VAT)	mln AMD	20,253	29,586	40,054
Expected Generation	GWh	2,097	2,097	2,357
One-part tariff (w/o VAT)	AMD/ kWh	9.658	14.108	16.995

Source: Bank team estimates.

Feed-in Tariffs

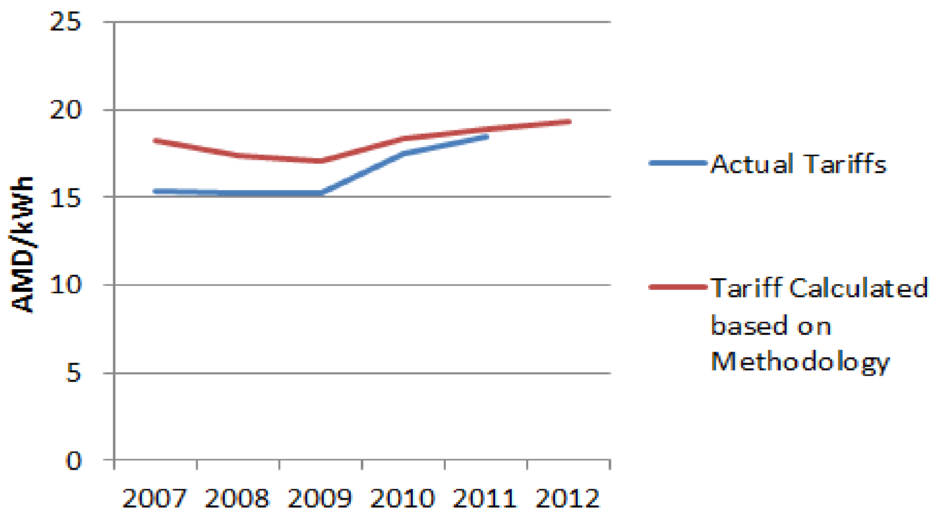
Data from the PSRC suggests that tariffs were not initially set at levels indicated by the 2007 resolution (see Box 1.2). Additionally, tariffs for renewable energy technologies other than small HPPs, including wind and biomass, have failed to

[9] Based on a desk review of life extension investment costs in the UK, Russia, and the US.

attract substantial private investment. Below cost-recovery feed-in tariffs for these technologies is often cited as a reason for the lack of investment.

It appears that tariffs for small HPPs have been adjusted and are approaching tariff levels in line with the feed-in tariff methodology. Figure 2.2 shows actual tariffs for small HPPs from 2007 to 2011 versus tariffs levels adjusted for consumer price index and exchange rate fluctuation required by the methodology. For the purposes of estimating short-term tariffs, the estimate of the feed-in tariff for 2012 was adjusted according to inflation and exchange rate fluctuation as indicated in the tariff methodology.

Figure 2.2: Actual Feed-In Tariffs versus Tariffs Calculated based on Tariff Methodology for Small HPPs



Source: Actual tariffs (PSRC), CPI (IMF WEO), exchange rate (WDI).

2.3 Additional Concerns about Cost-Recovery Tariffs

Several other aspects of tariff setting indicate that tariffs do not reflect an efficient cost of service. These include:

- **Depreciation rates for transmission and distribution.** The 4 percent depreciation rate that the PSRC uses for transmission and distribution equipment implies a 25 year asset life. This may be a reasonable assumption for some distribution equipment, but is too short of a period for transmission assets, which tend to have a useful life of 40 years. We have adjusted the depreciation rate for transmission assets to reflect a more realistic estimate of the asset life, but have not made adjustments to the depreciation rate for distribution.
- **Non-fuel variable costs**. Non-fuel variable operations and maintenance costs, including salaries, materials, and repairs, have remained constant for the past several years in the tariff calculation for most companies. We lacked sufficient data from the PSRC to recalculate these costs. However, the lack of change from year to year indicates that these costs have not

been appropriately adjusted to reflect changes in generation (or transmission) by plant and inflation.

- **Lack of explicit pricing for natural gas imported from Iran**. As described at the beginning of this section, the gas-electricity swap with Iran has allowed Armenia to take advantage of excess capacity during off-peak hours and trade this for natural gas, which is needed to run the more expensive TPPs to meet peak demand. The swap effectively creates a universal subsidy for all customers. This subsidy distorts price signals by not reflecting the explicit market-based price of natural gas in end-user tariffs. This implicit subsidy is a policy decision the Government of Armenia has made, which does not harm the financial or operational performance of any company in the sector. As a result, we do not attempt to estimate an explicit price for natural gas and have instead modeled our tariffs based on the terms of gas-electricity swap.[10]

Box 2.1: Gas-Electricity Swap with Iran

The Government of Armenia has negotiated a gas for electricity swap with the Government of Iran, under which Iran trades 1 m^3 of gas for 3 kWh of electricity from Armenia. This gas is used to produce electricity primarily at Yerevan CCGT, but can also be used to produce electricity at Hrazdan 5. Currently Armenia benefits from this arrangement in two principal ways:

- Yerevan CCGT actually produces 4.5 kWh of electricity per 1 m^3 of gas, so roughly 30% of the electricity generated by this plant remains in the domestic market. For electricity sold in the domestic market, Yerevan CCGT receives a reduced tariff which has no fuel cost component.
- Armenia trades energy – not capacity – with Iran. Each year an amount of electricity and gas to be swapped is agreed between officials from the two countries. Armenia has the flexibility of supplying the required electricity to Iran during the entire year and the deal is reportedly structured the way that Iran imports from Armenia when excess supply is available. This is beneficial for two primary reasons:
  - In the winter when consumption is highest in Armenia, Yerevan CCGT, which is the most efficient gas-fired plant in Armenia, can be used to generate for domestic consumption. Then, this plant can be run almost exclusively for export during the summer when the capacity is not needed or only needed occasionally to meet peaks in Armenia and Iran's demand is highest.
  - Yerevan CCGT, which is the only company that is licensed to export electricity, can buy excess supply from cheaper plants during spring and summer months and export it to Iran. This allows Armenia to meet the terms of the export arrangement with even cheaper supply than is available from Yerevan CCGT.

Source: Bank team.

[10] Box 2.1 describes the details of Armenia's gas-electricity swap with Iran and how it benefits Armenian customers. Appendix A describes the assumptions used to model these benefits.

3 Impact of New Investments on Tariffs

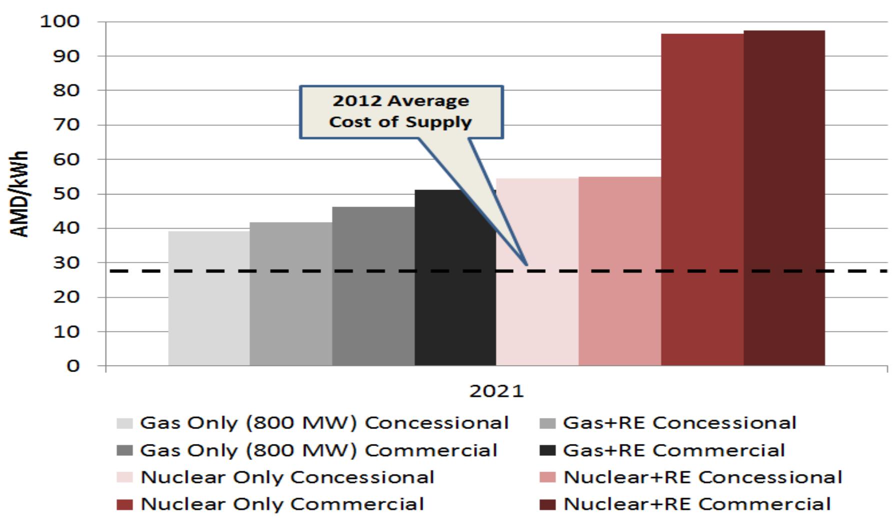
Investments in new generation to replace the ANPP will require large increases in end-user tariffs. However, the choice of generation technology to replace the ANPP significantly affects how large the increase will need to be. The ANPP, originally scheduled for decommissioning in 2016, is expected to remain operational through 2020. The Government has indicated its plans to build a new 1,100 MW nuclear plant by 2021. A new nuclear plant of this size is expected to cost between US$5-6 billion. Conversely, a new gas plant of 800 MW would cost less than US$1 billion.

In this section, the impact of various new generation scenarios on the average cost of service and on average residential tariffs is assessed.[11]

3.1 Average Cost of Service

The average cost of service including VAT is expected to increase from AMD 27 /kWh in 2012 to AMD 39–97/kWh in 2021 depending on the generation technology and financing terms (concessional or commercial). This constitutes a 45-260 percent increase in the average cost of service. Beginning in 2021, roughly AMD 78-373 billion (1-5 percent of estimated 2021 GDP) will be needed in additional sector revenue annually to cover the cost of supply. The share of generation in total sector revenue will increase from roughly 60 percent in 2012 to 75-90 percent in 2021 as a result of the required investments. Figure 3.1 shows the average cost of service under the different generation scenarios. Table 3.1 shows the average cost of service, the percent increase in the average cost of service over existing levels and the revenue requirement under each scenario.

Figure 3.1: Average Cost of Service under Different Generation Scenarios, 2021 (including VAT)



Source: Bank team estimates.

[11] This analysis is based on the generation scenarios described in the World Bank's Energy Sector Note (2011). Our assumptions about plant size, costs, and financing terms are shown in Appendix A.

Table 3.1: Average Cost of Service and Revenue Requirement under Different Generation Scenarios

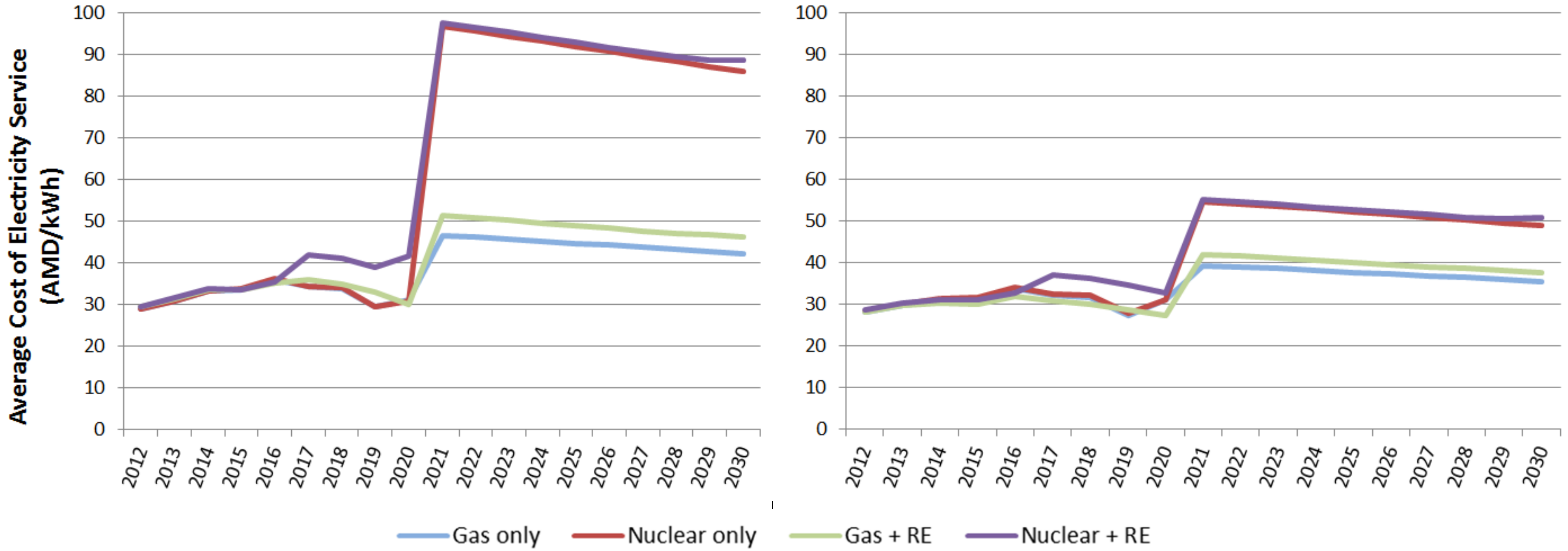
Generation Scenario		Average Cost of Service	Percent Increase over 2012	Revenue Requirement	Revenue Requirement
		AMD/kWh	%	million AMD	million US$
2012 (Actual)		27	---	125,405	322
Concessional	Gas Only	39	45%	242,111	622
	Gas+RE	42	55%	258,842	665
	Nuclear Only	54	101%	337,223	866
	Nuclear+RE	55	103%	340,014	873
Commercial	Gas Only	46	71%	286,705	736
	Gas+RE	51	90%	317,558	816
	Nuclear Only	97	257%	598,174	1536
	Nuclear+RE	97	260%	603,657	1551

Source: Bank team estimates.

The average cost of service stays relatively stable from 2013 to 2020, increasing slightly to account for investment in renewable energy in earlier years. The addition of new generation to replace the ANPP results in a large spike in the average cost of service from 2020 to 2021. Figure 3.2 shows the average cost of service under the eight generation scenarios for 2012-2030.

Figure 3.2: Average Cost of Service under Different Generation Scenarios, 2012-2030

Commercial Financing	Concessional financing



Source: Bank team estimates.

This analysis of the average cost of service demonstrates the following about generation options available to replace the ANPP:

- **New gas-based generation costs less than nuclear.** Gas-based generation is cheaper than nuclear in every scenario regardless of the financing terms or whether RE is built. This is primarily because of the benefits of the gas-electricity swap, which helps cushion gas plants against the increase of import price of gas from Russia.[12] Gas scenarios would be less attractive if the gas-electricity swap is not continued and the border price of Russian gas increases.
- **Concessional financing significantly reduces costs, particularly for nuclear.** Capital costs make up a significant portion of the levelized cost for a nuclear plant. As a result, financing terms have a large impact on the cost of service under nuclear scenarios. For example, the average cost of service assuming a nuclear plant with concessional financing is 56 percent of the average cost of service assuming commercial financing.
- **Renewable energy leads to a small increase in costs**. Adding new renewable energy capacity with a new gas or nuclear plant will slightly increase the average cost of service. These cost increases may be offset by the benefits from improved energy security and reduced carbon emissions. These results differ from those presented in the Energy Sector Issues Note (2011)[13] because of updated assumptions to model the benefits of the gas-electricity swap.

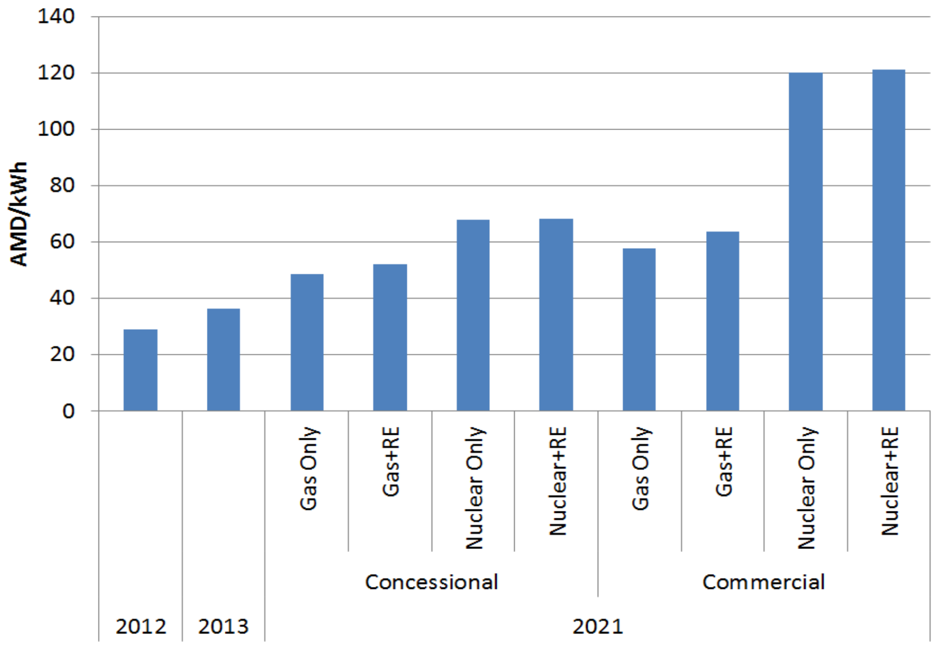
3.2 Average Residential Tariffs

The average residential tariff will need to increase 69–286 percent over the current tariff depending on the generation scenario. Figure 3.3 shows how the average residential tariff under the different scenarios compares to the 2012 actual average tariff and the 2013 short-run cost-recovery tariff. The average residential tariff is higher than the average cost of service. This reflects the fact that the cost of serving residential customers is higher than the cost of serving other customer groups. The allocation of costs to the residential class is based on our marginal costs analysis described in further detail in Section 4.2.3.

[12] We have assumed that Armenia meets the terms of the gas-electricity swap with Yerevan CCGT and any excess generation from the new gas plant. Our assumptions about the terms of the gas-electricity swap through 2021 are included in Appendix A.

[13] Ani Balabanyan, Artur Kochnakyan, Gevorg Sargsyan, Denzel Hankinson, and Lauren Pierce, "Charged Decisions: Difficult Choices in Armenia's Energy Sector," The World Bank, 2011.

Figure 3.3: Average Residential Tariff under Different Generation Scenarios, 2021



Source: Bank team estimates.

4 Marginal Cost-Based Tariff Structure

The current tariff structure does not reflect the way in which the costs of providing service are incurred by energy companies. This creates improper price signals leading to inefficient consumption. As a result, customers over-consume during hours when costs are high and under-consume during hours when costs are low. Additionally, some costs are incurred by the companies regardless of whether electricity is consumed, but are billed based on consumption.

This section introduces a revised tariff structure for Armenia based on the marginal cost of service. Box 4.1 defines the marginal costs and the rationale for their use to determine the tariff structure. Section 4.1 shows the proposed marginal cost-based tariff structure and the impact this has on average monthly bills. Section 4.2 describes the primary ways in which the proposed tariff structure differs from the current tariff structure in Armenia.

Box 4.1: Using Marginal Costs to Determine the Tariff Structure

What are Marginal Costs?

Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must ask and answer the question: What are all the additional generation, transmission and distribution costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand, and number of customers? Given the characteristics of electricity supply and demand, the cost of additional consumption may differ depending upon the time of the change in output. As a result, it is important to estimate time-differentiated marginal costs of electricity service.

Why Estimate Marginal Costs?

There are several reasons to estimate marginal costs. First, economic theory indicates that prices, which reflect marginal costs, lead to the most efficient allocation of society's scarce resources. Efficient resource allocation should be one of the goals of price setting in a regulated industry. Second, cost information is essential for the design of appropriate time-differentiated rates. Finally, accurate estimates of marginal costs are key inputs for determining the benefits of load management, distributed generation and conservation programs, and for engineering studies such as acceptable loss levels in transformer specifications.

4.1 Proposed Tariff Structure

This study recommends considering a two-part tariff structure for all customer classes. The proposed end-user tariff structure includes:

- **Per kWh charge.** Per kWh charge reflects energy and capacity costs, which differ based on the time of use. Capacity costs would ideally be based on a per kW charge, particularly for the two largest customer classes whose demand can pose a capacity constraint at the distribution level. However, data were not available to estimate a per kW charge based on monthly demand.
- **Fixed monthly charge.** The fixed monthly charge reflects costs incurred with the addition of each new customer. These include the cost of

investment in meters as well as investments in and operations and maintenance of local distribution facilities.

Per kWh charge is differentiated by season and time-of-use as follows:

- Winter Peak: 8:01 AM -12:00 Midnight, September - February
- Winter Off-peak: 12:01 AM - 8:00 AM, September - February
- Summer Peak: 8:01 AM - 12:00 Midnight, March - August
- Summer Off-peak: 12:01 AM - 8:00 AM, March - August

Table 4.1 compares the proposed marginal cost-based tariff structure for all customer classes in 2013 to the current tariff structure in 2012. Section 4.2 explains how the proposed tariff structure reflects the marginal costs of electricity service.

Table 4.1: Proposed Marginal Cost-Based Tariff Structure for All Customer Classes, 2013

	Residential	0.4 kV	6 (10) kV	35+ kV
Current Tariff	(AMD/kWh)			
Day	30	30	25	21
Night	20	20	17	17
Marginal Cost-Based Tariff	(AMD/customer/month)			
Monthly Marginal Customer-Related Cost	2,551	7,365	120,805	718,610
Combined Marginal Energy and Capacity Costs	(AMD/kWh)			
Winter peak	35.8	35.8	34	23.2
Winter off-peak	9.7	9.7	9.4	8.8
Summer peak	5.2	5.2	5	4.7
Summer off-peak	2.9	2.9	2.8	2.6

Source: Bank team estimates.

As show in Table 4.2, customers are charged more for electricity consumed during winter peak hours under the marginal cost-based tariff structure. This significantly higher tariff during hours of the year when consumption, particularly for the residential class, is highest would lead to a 12-41 percent increase in the average monthly bills in winter and a 35-63 percent decrease in average monthly bills in summer. Residential customers would experience the largest increase in winter bills.

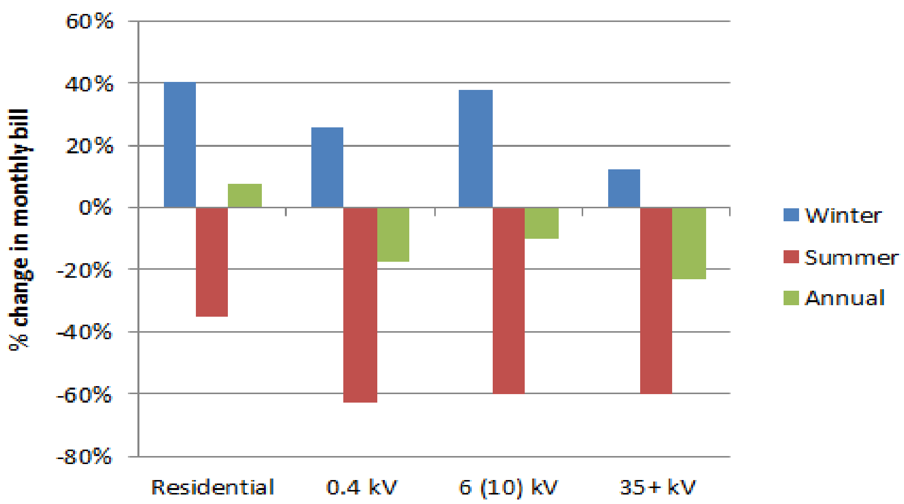
The marginal cost-based tariff structure also removes the cross-subsidy that currently exists between non-residential and residential customers. As a result, the average annual expenditure on electricity for households would increase 7 percent for residential households and would decrease 10-23 percent for non-residential customers. Table 4.2 compares the average monthly bill during winter and summer under the current tariff to the average monthly bill under the marginal cost-based tariff for all customers. Figure 4.1 shows the percent change between average winter and summer bills and annual expenditure on electricity with the marginal cost-based tariff.

Table 4.2: Impact of Tariff Structure on Monthly Bills for All Customer Classes

	Residential	0.4 kV	6 (10) kV	35+ kV
Monthly Bill Under Current Tariff Structure (AMD)				
Winter	6,790	38,532	618,324	3,842,677
Summer	5,305	36,510	585,871	3,640,995
Average	6,047	37,521	602,097	3,741,836
Monthly Bill Under Proposed Tariff Structure (AMD)				
Winter	9,550	48,524	851,736	4,316,219
Summer	3,439	13,533	232,943	1,454,873
Average	6,494	31,029	542,339	2,885,546

Source: Bank team estimates.

Figure 4.1: Percent Change in Monthly Bills under Proposed Tariff Structure



Source: Bank team estimates.

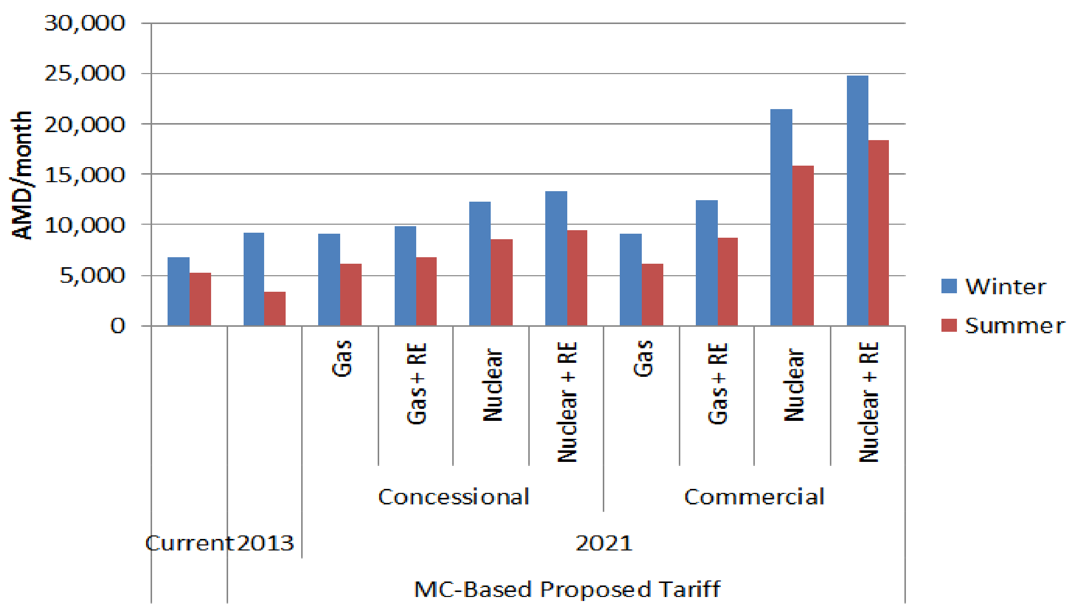
Table 4.3 shows marginal cost-based tariffs under different generation scenarios for 2021. The differential between monthly winter and summer bills is less significant in 2021 because of the higher fixed component spread evenly across all months. Figure 4.2 and Figure 4.3 compares monthly bills during winter and summer and the average annual expenditure, respectively, under the different scenarios.

Table 4.3: Marginal Cost-Based Tariff under Different Generation Scenarios, 2021 (VAT inclusive)

Scenarios		Monthly Marginal Customer-Related Cost (AMD/customer/month)	Combined Marginal Energy and Capacity Costs (AMD/kWh)			
			Winter peak	Winter off-peak	Summer peak	Summer off-peak
Concessional	Gas Only	6,052	23	7	6	6
	Gas + RE	6,052	26	10	9	9
	Nuke Only	6,052	36	20	20	20
	Nuke + RE	6,052	41	25	25	25
Commercial	Gas Only	6,052	31	15	15	15
	Gas + RE	6,052	37	21	21	20
	Nuke Only	6,052	77	61	60	60
	Nuke + RE	6,052	91	75	74	74

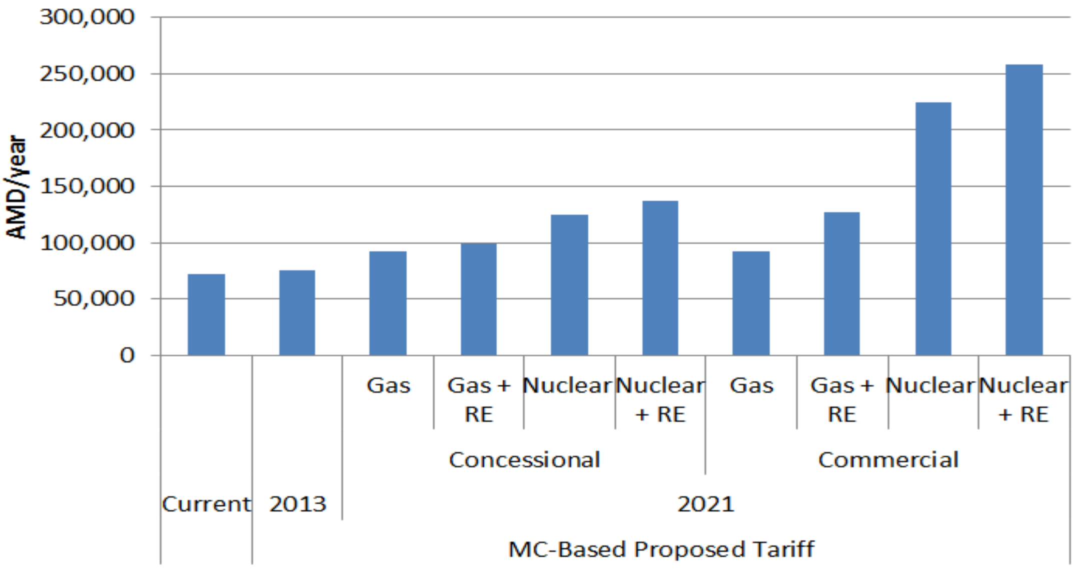
Source: Bank team estimates.

Figure 4.2: Monthly Bills in Winter and Summer under Different Generation Scenarios



Source: Bank team estimates.

Figure 4.3: Average Annual Electricity Expenditure under Different Generation Scenarios



Source: Bank team estimates.

4.2 How Does the Proposed Tariff Structure Differ from the Current Tariff Structure?

The marginal cost-based tariff structure differs from the current tariff structure in three important ways:

- **Seasonal time-of-use component.** The marginal cost-based tariff includes a seasonal component to reflect the difference in costs in winter and summer;
- **Fixed and variable components.** The marginal cost-based tariff includes both a fixed monthly charge and per kWh time-differentiated charges;
- **Class allocation.** The marginal cost-based tariff allocates the revenue requirement to customer classes based on their percentage share of marginal costs. This marginal cost-based allocation changes the revenue accrued from each customer class.

The following subsections describe each of these changes to the tariff structure and how they improve price signals to give customers a better indication of the marginal cost of electricity service. Appendix B provides further detail on how we estimated marginal costs and use these estimates to develop the proposed tariff structure.

4.2.1 Seasonal Time-of-Use Component

Under the current tariff, customers are charged the same day and night tariff regardless of whether their consumption occurs in winter or summer. This tariff structure fails to reflect the major differences in marginal costs between winter and summer. Marginal costs that vary from hour to hour include marginal generation capacity, energy, transmission capacity, and distribution capacity (subtransmission/distribution substation/feeder) costs.

These marginal costs are generally higher in September through February for the following reasons:

- **Peak demand occurs in winter.** In 2009-2011, Armenia's peak demand has occurred on the same day at roughly the same time in December. Transmission capacity is sized to handle annual peak demand on the transmission system. Therefore, the marginal cost of transmission capacity occurs in hours when the potential need for additional transmission capacity is highest. Our analysis shows a 99.9 percent probability that peak demand will occur and, therefore, marginal transmission capacity costs will be incurred during winter peak hours.[14]
- **Expensive thermal plants operate more frequently in winter to meet electricity based heating demand.** Hrazdan TPP runs primarily during winter months, leading to higher marginal energy and marginal generation capacity costs during this period. Hrazdan TPP has the highest variable costs among generators in the Armenian power system because it relies on gas from Russia and generates at a lower thermal efficiency than newer plants in the system. Hrazdan TPP is the last plant to be dispatched because of these high operating costs. The fact that Hrazdan TPP is running also indicates that the reserve margin, in other words, the difference between demand and available generation capacity, is lower in winter than in summer. We use the reserve margin to approximate the relative likelihood that load growth in a particular hour will trigger the need for additional capacity.[15] This, in turn, determines the likelihood that marginal generation capacity costs will be incurred. Our analysis indicates a 41 percent likelihood that additional capacity will be needed to serve winter peak demand compared to a 29 percent likelihood for summer peak.
- **Expensive thermal plants operate in September and October while the nuclear plant is shut down for maintenance.** The nuclear plant is scheduled for maintenance for 45 days beginning in September. Once every four years, the maintenance period is extended to 80 days to carry out larger rehabilitation projects and refueling. During this period, Hrazdan TPP operates more frequently to replace this capacity. Demand is not particularly high during September and October than in other months of the year. However, marginal energy and generation capacity costs are higher during this period because of reduced system capacity due to nuclear plant maintenance.

Marginal costs are typically lower in March through July because:

[14] Investment in subtransmission/substations/feeders depends upon growth in peak loads in the particular areas served by these facilities. Ideally, these marginal distribution capacity costs should be assigned to costing periods based on a statistical analysis of the patterns of hourly loads on substations. However, because that hourly information was not available, the same relative probability of peak estimates was applied to transmission costs to time-differentiate subtransmission/substation/feeder cost.

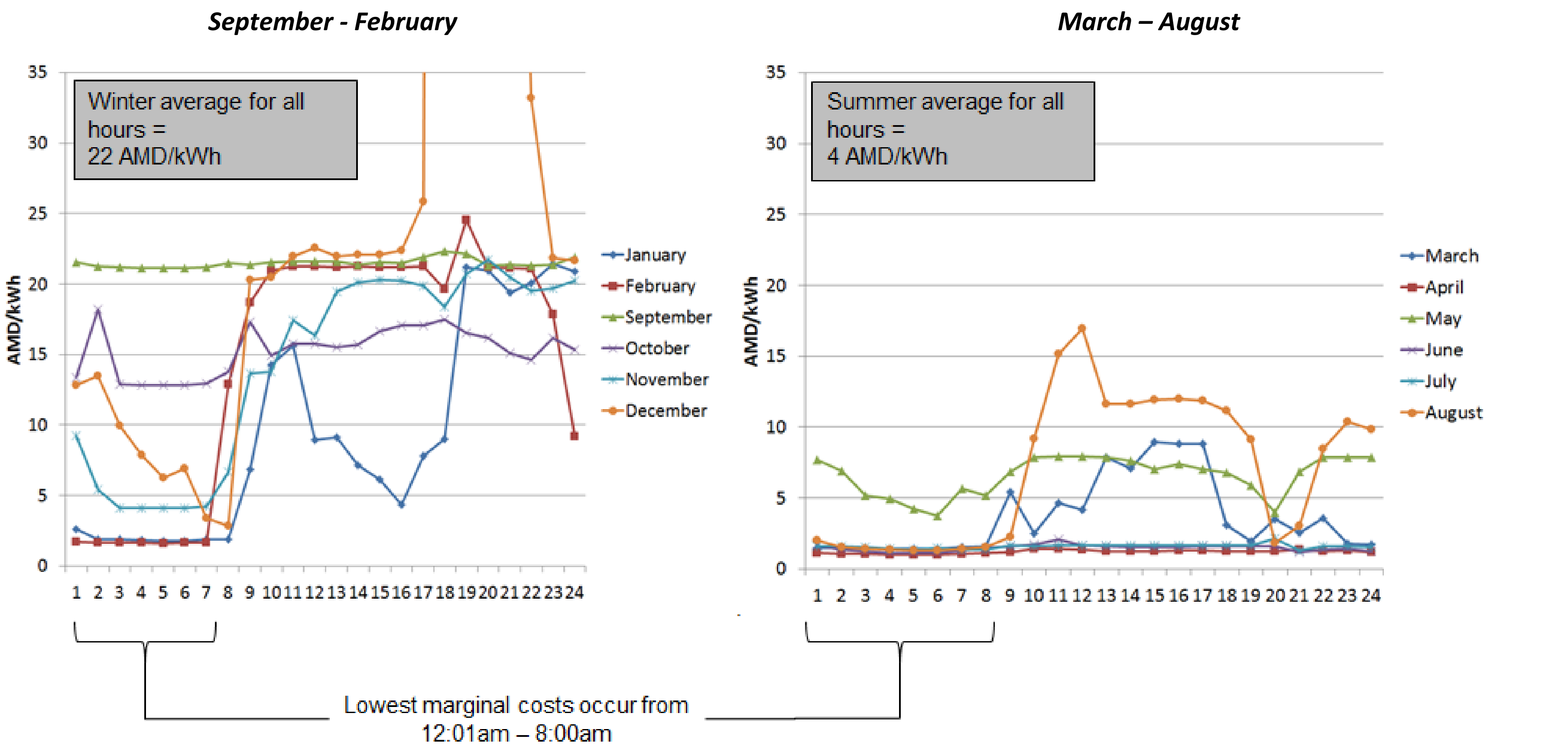
[15] This analysis approximates an hourly relative loss-of-load probability and is described in further detail in Appendix B.

- **Demand is lower, particularly during April through June.** Demand is lowest during April through June most likely because heat demand has ended and demand from air conditioning has not yet begun. As a result, the probability that marginal transmission and distribution capacity costs will occur during this period is low.
- **Lower cost supply is available from HPPs, particularly the Sevan-Hrazdan Cascade.** Supply from HPPs, which have the lowest marginal energy costs in the system, is highest during spring and summer months when run-of-river small HPPs generate with water from snow melt and the Sevan-Hrazdan Cascade operates at a higher capacity in line with agricultural demand for water.[16] The low demand during this period coupled with more available capacity also reduces the likelihood that marginal generation capacity costs will occur during this period.

We determined our seasonal and time-of-day per kWh pricing periods based on analysis of the sum of time-differentiated marginal costs during each hour of a typical day in each month. Our recommendation on pricing periods is based on an analysis of the plots of the resulting cost patterns across months and hours, while taking into consideration administrative feasibility and the need for the periods to be reasonably easy for customers to remember. Figure 4.4 shows a plot of these hourly costs averaged for the period 2013-2017.

[16] Water release from Lake Sevan is legally regulated in order to provide adequate water resources for irrigation and to maintain the lake's water levels.

Figure 4.4: Typical Day Average Hourly Marginal Costs per kWh, 2013-2017



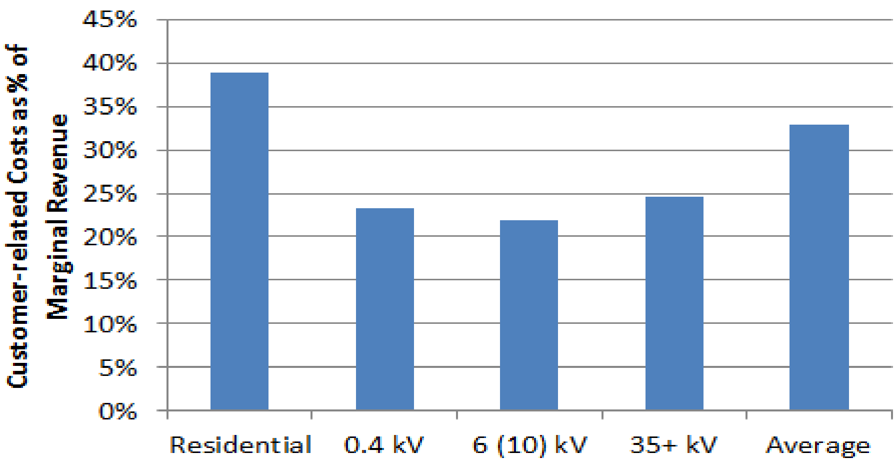
Source: Bank team estimates.

4.2.2 Fixed and Variable Components

Some costs at the distribution level vary based on the number and location of customers—not based on the addition of a kWh of consumption or a kW of demand. We refer to these costs as "customer-related" costs. It is typically more efficient to recoup "customer-related" costs through a fixed monthly charge as these costs do not vary based on a customer's actual peak load or consumption from month to month. We have assigned the following costs to this category: investments in local facilities and meter, customer-related O&M expenses, and an allowance for working capital.[17]

Customer-related costs account for a significant portion of marginal cost revenue, particularly for the residential class. This can be seen in Figure 4.5, which shows customer-related costs as a percentage of marginal cost revenue for each customer class in 2013. For this reason, we have recommended a monthly fixed charge per customer that reflects these customer-related costs.

Figure 4.5: Customer-related Costs as a Percentage of Marginal Cost Revenue by Customer Class, 2013



Source: Bank team estimates.

4.2.3 Revised Class Allocation

We have used two approaches to allocate revenue to customer classes based on marginal costs:

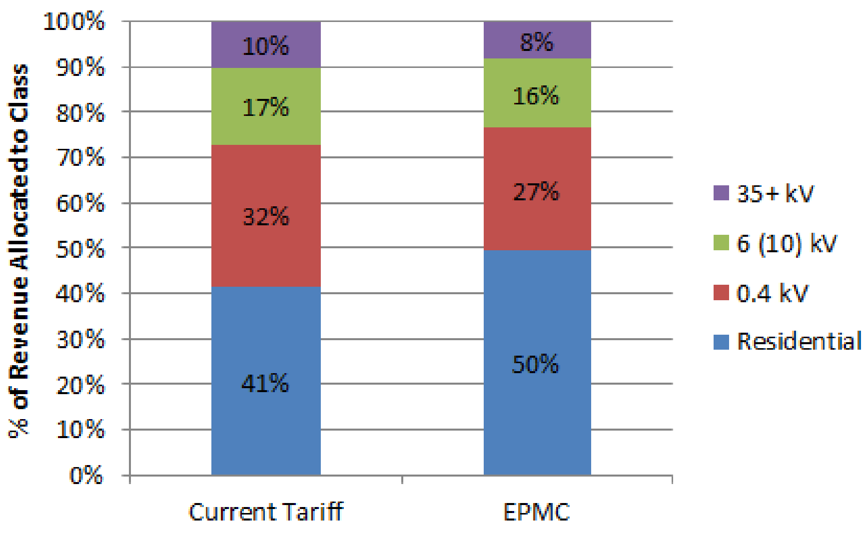
- **Equal Percentage of Marginal Cost (EPMC).** EPMC ensures that the class' share of the revenue requirement is equal to the class' share of marginal cost revenue. This is the most common approach for preserving marginal cost price signals. For example, if the residential class comprises 25 percent of marginal cost revenue, then its share of the revenue requirement will also equal 25 percent. This approach is consistent with the theoretically most efficient "Ramsey pricing," which allocates revenue to classes in inverse proportion to their elasticities of demand, when all classes' elasticities are the same. Reliable estimates of class elasticities of demand are rarely available for a quantitative application of Ramsey pricing.

[17] These costs and their estimates are described in further detail in Appendix B.

- **EPMC without customer-related costs.** EPMC without customer-related costs ensures that the class' share of the revenue requirement is equal to the class' share of marginal cost revenue when customer-related costs are excluded. Using a straight EPMC approach can sometimes create a significant revenue burden for a single class when tariffs have not previously been based on marginal cost. When this is the case, as it is in Armenia, it is acceptable to use a modified approach to EPMC. The modified EPMC approach reduces the residential share of the revenue requirement because customer-related costs are a higher share of marginal costs for the residential class than for non-residential customers. The modified EPMC approach helps reduce the burden on the residential class while preserving economic efficiency because customers are least price-sensitive to the fixed components of their bills. This means that accurate signaling of marginal customer costs is much less important for efficient allocation of resources than the price signals for electricity consumption. We use this approach in our determination of the marginal cost-based tariff structure for tariffs in 2021.

As mentioned in Section 1.2, the PSRC lacks a methodology for allocating revenue to customer classes. The revenue collected from the residential class under the current tariffs is lower than it would be if revenue were allocated using EPMC. A marginal cost-based tariff using straight EPMC would remove this cross-subsidy between the residential class and non-residential classes. Figure 4.6 compares class percentage of total revenue collected from each class under the current tariff to the revenue allocated using EPMC.

Figure 4.6: Comparison of Class Revenue Allocation under Current Tariff versus EPMC



Source: Bank team estimates.

5 Social Impact of Higher Tariffs

The tariff increases estimated in Section 3.2 will make electricity unaffordable for a larger portion of the population than currently, and could push more people below the poverty line. This section analyzes electricity affordability under current tariffs and analyzes how four options for new generation with two financing scenarios will impact affordability.

5.1 Affordability under Current Electricity Tariffs

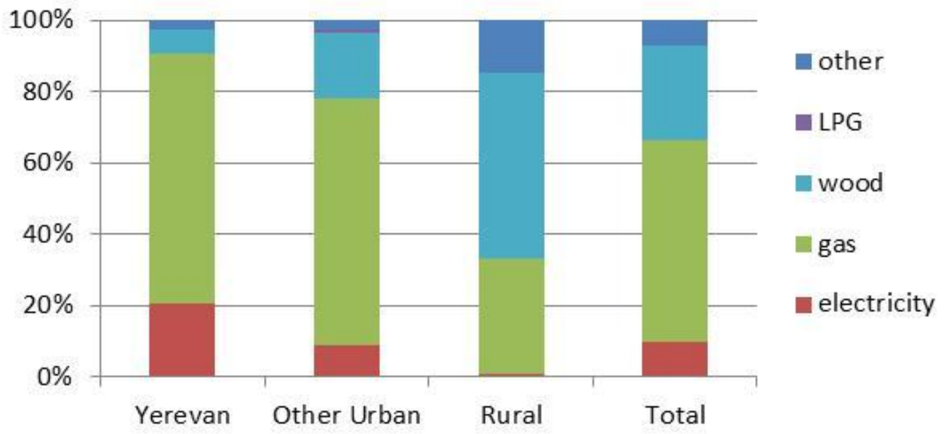
The global economic crisis increased the already high incidence of poverty in Armenia despite some mitigation through social assistance of last resort. In 2008-2010, the poverty incidence increased from 27.6 percent to 35.8 percent and severe poverty grew from 12.6 percent to 21.3 percent of the total population.[18] Urban areas other than Yerevan host the largest share of the approximately 1.2 million poor in Armenia. Targeted social assistance, such as PFBP, helped mitigate the poverty impacts of the global crisis. Poverty among FB recipients increased by 7 percent in 2008-2010 compared to 30 percent increase for the population as a whole.

Average household expenditure on energy increased from 7.9 percent in 2008 to 9 percent in 2010 despite a decrease in electricity consumption during this period. This is largely due to electricity expenditure, which accounts for almost half of total household spending on energy and has increased since 2008. The poorest quintiles of the population and urban households allocate a relatively higher share of their budgets to electricity than non-poor and rural households. The share of household expenditure devoted to electricity is also linked to the availability and usage of alternative energy sources, particularly gas. While access to electricity is almost universal, access to gas is generally lower among the poor, and in rural areas.

The pattern of energy use, and particularly the source of energy used for heating, affects household expenditure on energy and electricity. For instance, as Figure 5.1 shows, rural households spend a smaller share of their total expenditure on gas and electricity than the national average because many still rely on firewood as a source of heating. Spending on firewood is not always fully captured within the calculations of energy expenditures because it sometimes comes from households' own production. Nevertheless, increased firewood use, whether reported as energy expenditure or not, represents a strong explanation for lower electricity spending.

[18] The poor are defined as those with consumption per adult equivalent below the upper general poverty line; the severely poor are defined as those with consumption per adult equivalent below the lower general poverty line. The poverty line in 2010 was computed using the actual minimum food basket and the estimated share of non-food consumption in 2009.

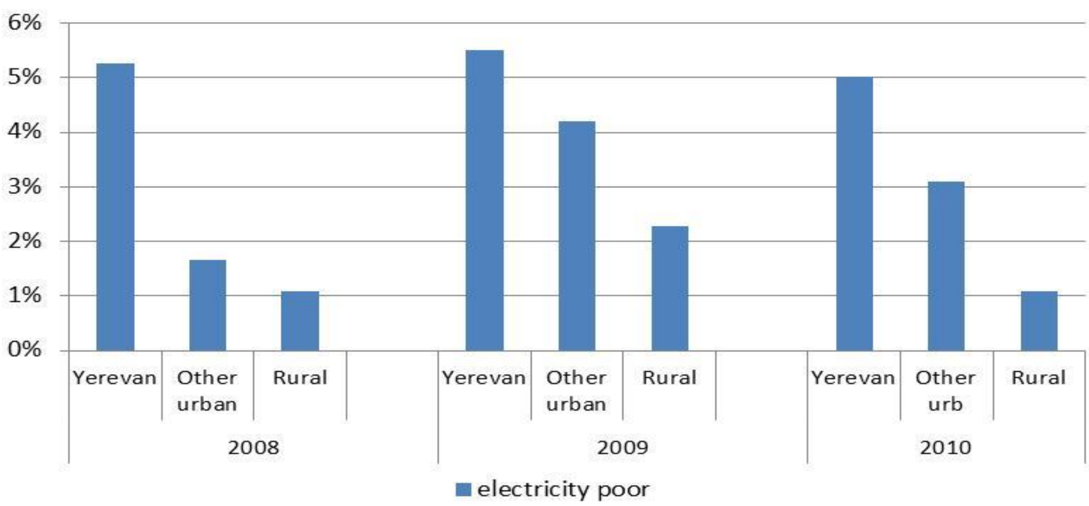
Figure 5.1: Patterns of energy use, source of heating by region (2010)



Source: Bank team.

Electricity poverty refers to households spending more than 10 percent of their budgets on electricity. These households are likely to experience more significant pressures on their budgets as a result of increased electricity tariffs. Electricity poverty affected about 3 percent of households in 2010. Electricity poverty is the highest among urban households and households in the poorest quintiles. As illustrated in Figure 5.2, electricity poverty is particularly pronounced in urban areas, including Yerevan, as a consequence of the relatively higher reliance on electricity for heating (over 20 percent of households).

Figure 5.2: Energy and electricity poverty (percentage of population), by region



Source: Bank team.

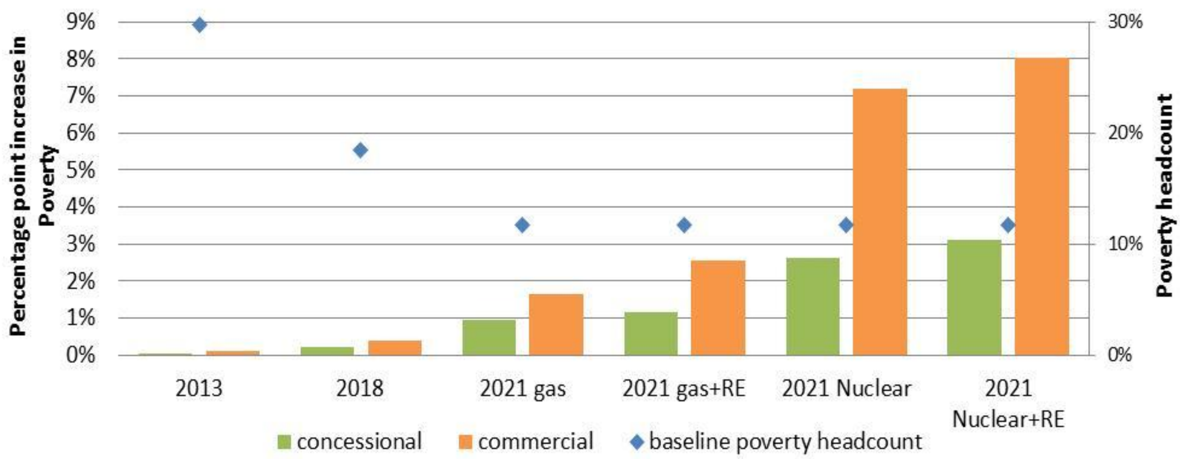
5.2 Impact of Higher Electricity Tariffs

As shown in Section 3.2, the tariff increase required to achieve a marginal cost-based cost-recovery tariff varies greatly depending on the generation investment scenario. Relying on commercial rather than concessional financing would result in the largest increase in the average tariff as compared to 2010. With concessional financing, the increase in average tariff to recover the full cost of electricity generation is estimated at 39-46 percent for gas-based generation options and 80-91 percent for nuclear plant options. Commercial financing scenarios are estimated to increase tariffs by 61-78 percent for gas-based generation and up to 239 percent for the nuclear + RE option.

The simulation analysis suggests that, if unmitigated, these tariff increases could increase poverty by 1-8 percentage points compared to the baseline for 2021 (see Figure 5.3).[19] In the absence of mitigation measures all nuclear generation options would cause larger increases in poverty than the gas generation options. The gas options would increase the poverty headcount by 1-2.6 percentage points, while the nuclear options would increase poverty by 3-8 percentage points.[20]

Vulnerable groups, such as FB beneficiaries and households already spending a significant amount on electricity, would be hardest hit by the tariff increases. In particular, as demonstrated in Figure 5.4, 9-10 percent of FB beneficiaries would become poor under the nuclear option with commercial financing.

Figure 5.3: Simulated poverty impact of electricity price increase, for different 2021 scenarios

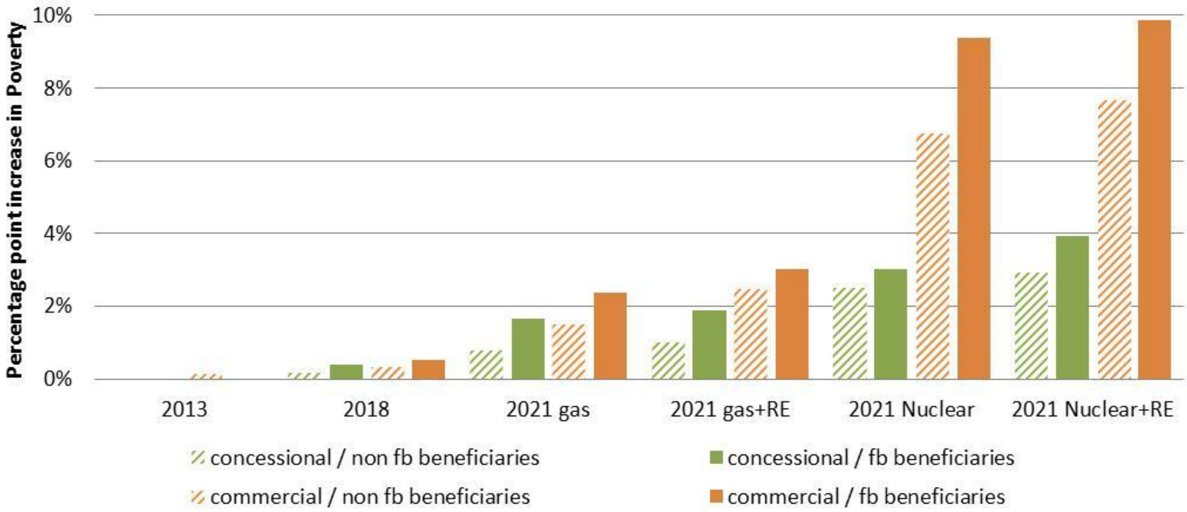


Source: Bank team estimate.

[19] The main assumptions for the analysis presented above were: (i) Expenditure and electricity consumptions at the household level are provided by the ICLS survey 2010, representative of the Armenian population as a whole. (ii) For each milestone year (2013, 2018, 2021), the increase in welfare is assumed to be proportional to IMF growth increase estimates in real terms (the cumulated per capita growth in real terms is estimated at 9.4 percent in 2012, 26.64 percent in 2018 and 38.26 percent in 2012). Assumptions on the subsequent electricity consumption increase are consistent with the price estimation model, taking into account an income elasticity of households' electricity consumption. As a consequence, electricity expenditures and electricity shares are shifted due to the expected increase in welfare prior to any price increase. (iii) A standard price elasticity of -0.25 is assumed for each price increase scenario and the impact on households of the price increase is estimated as a comparison to each year baseline.

[20] The most expensive options, i.e. the nuclear options, might lead households to reduce their electricity consumption significantly, thus limiting the expenditure increase. The costs of making such adjustments are however unknown at the moment and as such neither these major adjustments nor their costs are factored into the analysis.

Figure 5.4: Simulated poverty impact of electricity price increase by Family Benefit program status, for different 2021 scenarios



Source: Bank team estimate.

Household spending on electricity, particularly in poor households, would increase significantly under all tariff scenarios. The share of electricity expenses in the household budget would increase by 25-51 percent in 2021 for all households, reaching as much as 5 percent of total expenditure in the nuclear generation with commercial financing scenarios. The share of electricity expenses in the household budget would be particularly pronounced among the poor, who likely already minimize electricity spending and, therefore, cannot reduce consumption as the tariff increases.[21] Increase of the share of electricity expenses in the budget for these households could reach as much as 11 percent under the Nuclear + RE (commercial financing) scenario and as much as 17.7 percent for the electricity poor.

Without mitigation measures, electricity poverty would significantly increase in all simulated scenarios, especially among the poorest households. The results of simulations indicate that the additional increase in electricity poverty due to the tariff change would range between 2 and 5 percentage points. Electricity poverty incidence would increase from an estimated baseline of 1.63 percent in 2021 to 3.7-6.4 percent depending on the generation investment scenario. Vulnerability to tariff increases would be greatest among the poorest households. In the 2021 nuclear scenario with commercial financing, as many as 8.6 percent of poor households would be electricity poor, in the absence of mitigating measures.

[21] As mentioned above we assume a -0.25 constant elasticity for all groups. This is a somewhat conservative assumption as there is evidence that poorer groups have a lower elasticity than richer ones (see Fan Zhang for the case of Turkey).

6 Transitioning to Higher, Marginal-Cost Based Tariffs

The tariff increases estimated in Section 3 present two important challenges for Armenia's policymakers and the PSRC:

- The challenge of keeping electricity affordable for as much of the population as possible. As shown in Section 3.1, most of the likely scenarios for new investment will make electricity unaffordable for a larger portion of the population than currently, and risk pushing more people below the poverty line.
- The challenge of preventing "rate shock" among customers, in other words, customer discontent over the sudden and substantial tariff increases. Rate shock is more than a political problem. It can create real financial problems for electricity service providers in the form of lower collection efficiency and higher commercial losses. Rate shock is related to customer willingness-to-pay, but not necessarily to affordability.

Keeping electricity affordable means that some customers pay less than the full cost of service. The Government of Armenia will need to consider how subsidies can protect these customers from becoming poor or electricity poor, while also protecting the financial viability of the electricity sector. Section 6.1 describes the range of policy options for subsidizing customers who are at risk of becoming poor or electricity poor.

Mitigating rate shock also requires subsidies, but the subsidies are funded from customer classes (inter-class), from within customer classes (intra-class) or between current and future customers (intergenerational). Section 6.2 describes the options for mitigating rate shock.

6.1 Options for Subsidization

There are a number of measures the Government can consider to keep electricity affordable for low income customers, while at the same time preserving the financial sustainability of the sector. The various options are described and evaluated in this section.

6.1.1 Deciding on subsidy delivery options

Designing a subsidy regime generally requires decisions about: (i) How to identify the poor, (ii) How to deliver the subsidy, (iii) When to deliver the subsidy, and (iv) How to fund the subsidy. Options for each of these decisions are described and evaluated in the subsections below. Finally, the Government may also wish to consider what to subsidize. The discussion in most of this section assumes that the Government will subsidize electricity consumption, but Government may also wish to subsidize alternatives to electricity consumption, such as investments in energy efficiency.

How to identify the poor

As described in Section 5.1, Armenia has a well-established social support program, the PFBP. It was created in 1999 by integrating several Soviet-era categorically-targeted programs into a single proxy-means test program. Beneficiaries are identified according to a formula with thirteen means-testing variables, including measures related to electricity consumption and access to gas. The PFBP consists of cash benefits paid directly to the households, in the form of a basic lump sum regularly reviewed by the Government, plus a variable amount depending on family characteristics (e.g. number of children). Ongoing analysis of the targeting mechanism of the PFBP suggests that the formula could be improved to eliminate the exclusionary effect of some of the variables. In this way the coverage of the poor could be increased even with a constant budget.

As an alternative, customers could be identified based on their energy consumption. So-called lifeline tariffs are tariffs which are lower for certain customers based on the amount of household consumption. These tariffs are generally applied to the initial block of consumption, called the basic need level (for example 50 kWh). Lifeline tariffs can be in the form of volume differentiated tariffs, in which a lower tariff per KWh is applied only to households consuming an amount of electricity within the first consumption block. They can also be in the form of increasing block tariffs in which the lower tariff rate is applied universally to consumption within the first block, and consumption above that level is charged at a higher tariff rate. Finally, a variation on the lifeline tariff is to waive or partially waive, or to provide a credit or partial credit for the fixed monthly customer charge for a targeted group of customers.

On the one hand, lifeline tariffs allow for only very rough targeting of customers. Customers who use less than the lifeline volume may not be poor (for example, individuals with vacation homes). Customers who use more than the lifeline may not be wealthy (for example, households with many family members). On the other hand, if the poverty rate is high (as it is in Armenia) or the accuracy of alternative targeting mechanisms is low, lifeline tariffs may be the best option.

The Government does have some experience with lifeline tariffs. Lifeline tariffs were used in the electricity sector in the 1990s. More recently, in 2011, the Government introduced a temporary lifeline tariff for natural gas customers, however, this tariff was targeted to cover only FB beneficiaries.[22]

How to deliver the subsidy

Subsidies can be delivered directly to customers, as cash or vouchers, or indirectly, as discounts on customers' energy bills.

<u>Cash transfers</u> are a mechanism by which a government can increase consumers' purchasing power by supplementing the household income with allocations of money, which may be intended for a particular purpose, but are not required to be used in that way. The effectiveness of targeting the poor using cash transfer schemes depends on the institutional capacity to reach the intended beneficiaries. Armenia currently has high institutional capacity to implement a cash transfer scheme through the FB program.

<u>Voucher schemes</u>, or near-cash transfers to households, also aim to increase consumers' purchasing power; however, unlike cash, which can be used to buy anything, vouchers are designated for a specific purpose such as the purchase of electricity. Voucher programs have a low cost to the government budget compared to universal subsidy programs; however, the administrative costs of voucher programs tend to be higher than that of cash transfer programs because the development and distribution of vouchers is inherently more complicated than the distribution of cash. A voucher program in Armenia may be administered through the FB program.

[22] Under the current gas lifeline tariff, poor customers pay 100 AMD/m3 compared to regular tariff of 132 AMD/m3. This tariff holds for up to 300 m3 of gas consumed during the 1-year period.

Indirect delivery of the subsidy means subsidizing the electricity companies so that they are able to discount rates. This subsidy can be roughly targeted, for example through a lifeline tariff, or untargeted, for example when all end-user tariffs are set below cost-recovery levels.

When to deliver the subsidy

Traditionally, government subsidies to electricity companies have been delivered in lump sums, tied to budgeting cycles. As an alternative, output-based subsidies can be tied to actual consumption by customers identified as poor customers. Under an output-based subsidy regime, the electricity companies receive payment only after they have delivered the service, and can prove (through presentation of customer bills or vouchers) that they have delivered the service. It is also worth noting that output-based measures can also provide support for greater energy efficiency, as customers are first faced with higher prices which might lead them to adjust consumption, and then compensated at least partially for their higher energy spending.

How to fund the subsidy

Subsidies may be funded by direct transfer from government (to the utility or to PFBP), or through cross-subsidies from other customer classes (inter-class subsidies), or within a customer class (intra-class subsidies). The advantage of a cross subsidy is that it avoids using government funds. The disadvantage is that it distorts prices, and therefore will distort consumption by the customer classes that fund and receive the cross subsidy.

Alternative subsidy options

The Government can also help households consume less electricity, and thereby reduce their electricity bills, by promoting energy efficiency. For example, the Government could provide a subsidy to households for purchasing energy efficient equipment or to carry out a home energy audit. The Government has experience with this type of subsidy program through the Renewable Resources and Energy Efficiency Fund (R2E2), which provided subsidies for individual gas heaters for poor households. This type of scheme could be replicated for other EE equipment or services and could accompany a recurrent subsidy program aimed to reduce monthly energy expenditures of poor households.

6.1.2 Evaluating subsidy delivery options

We have developed seven possible subsidy delivery options based on different alternatives for identifying the poor, delivering the subsidy, and funding the subsidy.

Table 6.1 describes each of these options in further detail.

Table 6.1: Subsidy Delivery Options

Subsidy Mechanism	Brief Description	Targeting	Delivery	Funding
Reduced tariff for all customers	Below cost-recovery tariff subsidized for all residential customers	Untargeted	Directly to sector companies	Direct Transfer or cross-subsidy
Voucher Program/Cash Transfer to FB beneficiaries	Below cost-recovery tariff subsidized for FB beneficiaries only	Targeted – FB beneficiaries only	Cash transfer/ voucher	Direct Transfer
Voucher Program/Cash Transfer to All Poor Households	Below cost-recovery tariff subsidized for all poor households	Targeted – All poor households	Cash transfer/ voucher	Direct Transfer
Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries	30 percent discount provided on the first 100 kWh to FB beneficiaries	Targeted – All poor households	Cash transfer/ voucher	Direct Transfer
Lifeline tariffs - Increasing Block Tariff for all customers	Below cost-recovery tariff for consumption up to 100 kWh/month	Untargeted	Directly to sector companies	Direct Transfer or cross-subsidy
Lifeline tariffs - Increasing Block Tariff for FB beneficiaries	Below cost-recovery tariff for consumption up to 100 kWh/month for FB beneficiaries only	Targeted – FB beneficiaries only	Directly to sector companies	Direct Transfer or cross-subsidy
Lifeline tariffs - Volume Differentiated Tariff for all customers	Below cost-recovery tariff for households consuming below 100 kWh/month	Untargeted	Directly to sector companies	Direct Transfer or cross-subsidy

Source: Bank team.

We assess the subsidy delivery options described above based on the following criteria:

- Economic distortion—the degree to which each option distorts marginal cost price signals and/or distorts consumption patterns and preferences;

- Administrative and fiscal costs—the administrative and fiscal cost burden imposed on the Government as a result of administering and funding the subsidy program;
- Targeting—the extent to which the subsidy is exclusively delivered to poor households;
- Coverage—the extent to which all poor households receive the subsidy.

Table 6.2 to Table 6.5 compare each of the above subsidy options in terms of each of these four criteria. It should be noted, however, that there is some correlation between criteria. For example, subsidy mechanisms that are better targeted to poor households tend to be less distortionary and have a lower fiscal burden.

Table 6.2: Comparison of Subsidy Options in terms of Economic Distortion

<table>
<tr><th>Subsidy Option</th><th>Rank[23]</th><th>Explanation</th></tr>
<tr><td>Reduced tariff for all customers</td><td>7</td><td>Indirect transfers to sector companies to reduce the tariff for all customers can be the most distortionary if they are used to reduce tariffs below marginal cost, which creates distortionary price signals for all consumers[24]</td></tr>
<tr><td>Voucher Program/Cash Transfer to FB beneficiaries</td><td>1</td><td rowspan="3">Economic distortion is least present with cash transfers or vouchers, which could be used to target FB or poor households:
▪ Vouchers, particularly those that are based on non-consumption criteria, such as household size and income, are less distortionary because they do not distort the market price of goods. They do, however, influence the allocation of household spending to be different than if there was no subsidy program
▪ Cash transfers are least distortionary because they increase the disposable income of a household rather than altering the price of goods or changing consumption preferences or patterns</td></tr>
<tr><td>Voucher Program/Cash Transfer to All Poor Households</td><td>1</td></tr>
<tr><td>Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries</td><td>3</td></tr>
<tr><td>Lifeline tariffs - Increasing Block Tariff for all customers</td><td>6</td><td rowspan="3">Lifeline tariffs, particularly those that provide a subsidy based on consumption provide distortionary price signals for the first block of consumption because the tariff is less than the marginal cost of the service</td></tr>
<tr><td>Lifeline tariffs - Increasing Block Tariff for FB beneficiaries</td><td>5</td></tr>
<tr><td>Lifeline tariffs - Volume Differentiated Tariff for all customers</td><td>4</td></tr>
</table>

Source: Bank team.

[23] 1 = Least distortionary; 7 = Most distortionary.

[24] When marginal cost is below the tariff required to recover the utility's long-term average costs, then a direct transfer to cover the gap between marginal cost and actual cost is not considered distortionary.

Table 6.3: Comparison of Subsidy Options in terms of Costs

<table>
<tr><th>Subsidy Option</th><th>Fiscal Cost (bln AMD/year)</th><th>Rank[25]</th><th>Explanation</th></tr>
<tr><td>Reduced tariff for all customers</td><td>24-147</td><td>7</td><td>Untargeted subsidies inherently subsidize all consumers and are therefore most costly.</td></tr>
<tr><td>Voucher Program/Cash Transfer to FB beneficiaries</td><td>1.6-14.8</td><td>4</td><td rowspan="3">Fiscal costs of vouchers would be lower because they could be targeted to poor families and/or FB beneficiaries. The administrative costs of voucher programs tend to be higher than that of cash transfer programs because the development and distribution of vouchers is inherently more complicated than the distribution of cash.
Cash transfers tend to be lowest cost because they target only poor households and are least complicated to administer. This is particularly true in Armenia where institutional capacity already exists through the FB program to deliver cash transfers.</td></tr>
<tr><td>Voucher Program/Cash Transfer to All Poor Households</td><td>1.5-14.5</td><td>3</td></tr>
<tr><td>Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries</td><td>1.4-3.6</td><td>2</td></tr>
<tr><td>Lifeline tariffs - Increasing Block Tariff for all customers</td><td>12.3-75.7</td><td>6</td><td rowspan="3">The cost of lifeline tariffs depends on how they are targeted. Lifeline tariffs which provide below cost recovery tariffs for all consumers for the first block of consumption are inherently more costly than those which are only provided to poor households.</td></tr>
<tr><td>Lifeline tariffs - Increasing Block Tariff for FB beneficiaries</td><td>1.4-3.3</td><td>1</td></tr>
<tr><td>Lifeline tariffs - Volume Differentiated Tariff for all customers</td><td>2.7-60.8</td><td>5</td></tr>
</table>

Source: Bank team.

[25] 1 = Lowest Cost; 7 = Highest Cost.

Table 6.4: Comparison of Subsidy Options in terms of Targeting

Subsidy Option	Targeting		Rank[26]	Explanation
	Non-Poor	Poor		
Reduced tariff for all customers	90%	10%	7	Untargeted subsidies tend to be highly regressive, in other words, wealthier households receive a larger proportion of the subsidy than poorer households. This happens because wealthier households tend to consumer more and therefore receive a larger portion of the subsidy in absolute terms.
Voucher Program/Cash Transfer to FB beneficiaries	60%	40%	4	Inclusion of the non-poor is minimized in targeted cash transfer and voucher programs, but depends to some extent on the institutional ability to identify poor households. In Armenia, targeting of poor households through the FB program is good, but could be improved. In 2010, 76.5 percent of the benefits reached households that were considered poor before any Social Assistance transfer. The targeting accuracy increased from the already high 2008 level (66.8 percent).
Voucher Program/Cash Transfer to All Poor Households	0%	100%	1	
Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries	55%	45%	3	
Lifeline tariffs - Increasing Block Tariff for all customers	88%	12%	6	Increasing block tariffs tend to have high inclusion of the non-poor, because the benefit is given to all groups regardless of income. Volume differentiated tariffs have better targeting of the poor because the low tariff rate is given only to households using at or below the initial consumption block, however, this is based on the broad assumption that poor income households tend to consume less electricity. Targeted increasing block tariffs have lower inclusion of non-poor than other lifeline tariff options.
Lifeline tariffs - Increasing Block Tariff for FB beneficiaries	55%	45%	2	
Lifeline tariffs - Volume Differentiated Tariff for all customers	82%	18%	5	

Source: Bank team

[26] 1 = Most Targeted; 7 = Least Targeted.

Table 6.5: Comparison of Subsidy Options in terms of Coverage

Subsidy Option	Targeting			Rank [27]	Explanation
	Total	Non-Poor	Poor		
Reduced tariff for all customers	98%	99%	98%	1	Untargeted subsidies inherently cover all poor households as well as all non-poor households.
Voucher Program/Cash Transfer to FB beneficiaries	13%	8%	43%	4	The prevalence of exclusion of poor households is dependent on the institutional ability to identify poor households. Targeting in the FB program, which would be used to deliver cash transfers or vouchers, is good, but coverage could be improved. Only 26.2 percent of poor households were covered by the FB program in 2010, compared to the 33.7 percent coverage in 2008).
Voucher Program/Cash Transfer to All Poor Households	15%	0%	98%	1	
Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries	13%	8%	43%	4	
Lifeline tariffs - Increasing Block Tariff for all customers	98%	98%	98%	1	Increasing block tariffs inherently cover all poor households (as well as non-poor households) for the first block of consumption. Volume differentiated lifeline tariffs assume that electricity consumption is correlated to income. In many cases this is true; however, poorer families are often larger than non-poor families[28], and as a result volume differentiated lifeline tariffs have the potential to exclude poor families, which consume more electricity due to household size.
Lifeline tariffs - Increasing Block Tariff for FB beneficiaries	13%	8%	43%	4	
Lifeline tariffs - Volume Differentiated Tariff for all customers	19%	17%	34%	7	

Source: Bank team

6.2 Options for Mitigating Rate Shock

The PSRC has a number of options for mitigating rate shock.[29] These options exist at all stages of the tariff-setting process shown in Figure 1.1: 1) Estimation of the Revenue

[27] 1 = Highest Coverage; 7 = Lowest Coverage.

[28] When marginal cost is below the tariff required to recover the utility's long-term average costs, then a direct transfer to cover the gap between marginal cost and actual cost is not considered distortionary.

[29] Subsidy policy is typically regarded as the responsibility of policymakers, not regulators. Nevertheless, it is typical in countries with long-standing traditions of independent utility regulation (for example, the US) for regulators to decide the nature of cross subsidies required to mitigate rate shock. We therefore refer to the PSRC instead of the Government of Armenia throughout this section, as it is reasonable to expect that it would be the PSRC's decision on how best to mitigate rate shock.

Requirement, 2) Allocation of the Revenue Requirement, and 3) Design of the end-user tariff structure. The subsections below describe the options for mitigating rate shock at each stage of the tariff-setting process.

6.2.1 Estimating the Revenue Requirement

The PSRC, like many regulators, uses straight-line depreciation to determine the depreciated, or residual, value of the utility's assets. This residual asset value is a key component in establishing the rate base,[30] which, in turn, drives the capital expenditure portion of the revenue requirement. Using straight-line depreciation, the revenue requirement is larger in the initial years when the full value of the asset is included in the rate base and decreases over time as the asset depreciates. This "front-end loading" of capital cost recovery can cause rate shock as tariffs must increase significantly to cover the higher revenue requirement in the initial years of operation of new generation assets.

Alternative approaches to calculating the rate base can mitigate the impact of rate shocks. The following subsections discuss two of these approaches—construction work in progress (CWIP) and cost recovery deferral, or creating a regulatory asset—and an additional transition subsidy mechanism that could be used if the level of annual increase in the tariff is considered unsustainable for the majority of the population.

Construction Work In Progress in the Rate Base

The construction work in progress (CWIP) regulatory accounting method allows a utility to recover construction-related financing costs as they are incurred rather than capitalizing these financing costs and incorporating them into the rate base once the asset is operational.

This approach mitigates rate shocks in two ways. First, using CWIP, the regulator can gradually include the costs of new assets into the tariff. This allows customers time to adjust consumption habits and make decisions about purchasing new equipment (for example, deciding to buy energy efficient appliances) to cope with higher rates. Second, CWIP eliminates the compounding of carrying costs[31], which has two benefits:

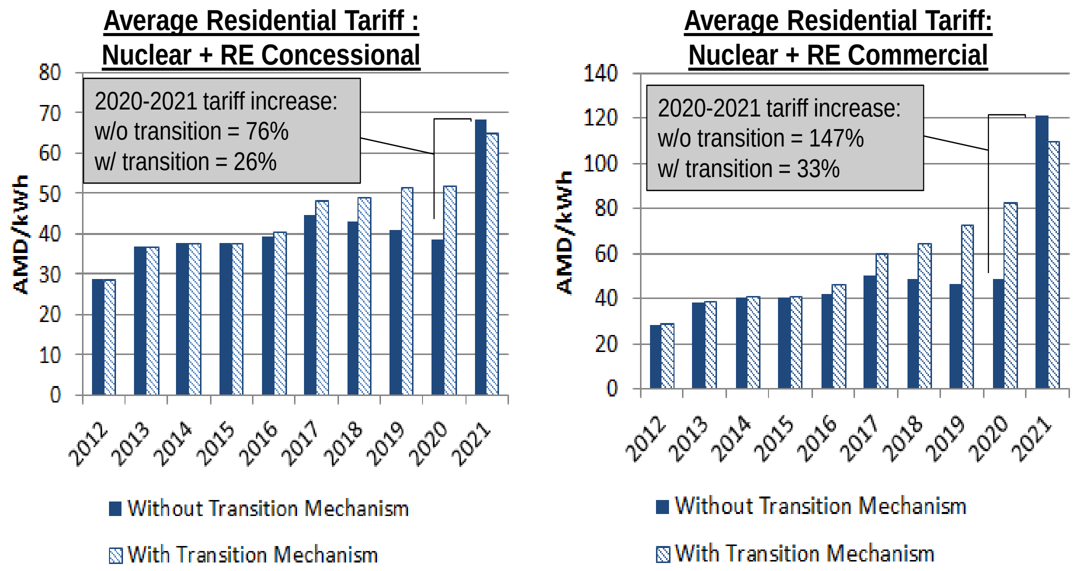
- Reduced overall project costs. CWIP reduces overall project costs by allowing the utility to recover financing costs as they are incurred. Without CWIP, carrying costs incurred before the asset is operational are capitalized, creating a larger asset base from which future carrying costs are calculated.
- Improved financial condition of the utility. CWIP improves the utility's cash flows. Improved cash flows increase the utility's credit-worthiness, allowing the company to borrow at lower interest rates in the future.

Figure 6.1 shows an example of how the CWIP method can be used to reduce regulatory rate shock for the construction of a new nuclear plant in Armenia. The figure shows the impact of CWIP assuming commercial and concessional financing scenarios.

[30] The rate base may include allowances for working capital and excludes any capital contributions from customers, government or third parties.

[31] In this context, carrying costs are equal to the weighted average cost of capital (WACC).

Figure 6.1: Examples of How CWIP Avoids Rate Shock for Two Nuclear Scenarios



Source: Bank team estimate.

CWIP is used, in particular, for capital intensive projects like new nuclear plants. Despite the benefits described above, CWIP has been criticized for:

- Allocating costs inequitably between customers across years. Some object to CWIP based on the principle that it is inequitable to charge consumers for an asset before they are receiving benefits from that asset. When this approach is applied regularly, however, current year's consumers benefit from contributions made by consumers in prior years.
- Transfering financing risk to the customer. Consumer advocate groups argue that CWIP requires the ratepayer to cover all of the costs and all of the risks of financing construction, and, unlike shareholders, ratepayers have no ownership or influence in the company.
- Reducing incentive to control costs. There is some concern that CWIP reduces a utility's incentives to control costs because they have a promise from the regulator that they will recover costs through end-user tariffs. The regulator can mitigate this, however, by establishing a pre-determined list of prudent expenditures which will be included in the rate base.

Despite these concerns, the US Federal Energy Regulatory Commission (FERC), two Canadian provinces and many US states have adopted legislation or have put in place regulations to allow for CWIP to be accounted for in rate base during the construction of certain large-scale, multi-year construction projects.[32] [33]

[32] As of 2010, the Canadian provinces of Ontario and British Columbia as well as 19 US states had adopted legislation or had legislation pending to allow for CWIP. (Pacific Economics Group Research LLC, "Innovative Regulation: A Survey of Remedies for Regulatory Lag." Prepared for the Edison Electric Institute. April 2011).

[33] Charles River Associates (CRA), "Benefits of Integrating CWIP into rate base in Ontario," Prepared for Ontario Power Generation. March 19,2010.

Creation of a "Regulatory Asset"

Creating a regulatory asset is another approach to smooth out rate increases over time in order to mitigate the impact of rate shocks. This allows the regulator to gradually increase the tariff to reflect the full value of a utility's capital costs after the asset is operational. This is done by deferring the financing costs associated with capital expenditure through the creation of a regulatory asset, in which the utility converts these costs from its income statement to its balance sheet. The regulatory asset is fully amortized over a specified, future period and a carrying cost is incurred on the unamortized balance. The utility cannot convert an expense to a regulatory asset until the regulator has approved that it will allow the company to fully recover costs through future rate adjustments.

There are three key drawbacks associated with creating a regulatory asset:

- **Creating a regulatory asset increases the total cost of financing**. Carrying costs accrue while the utility is deferring repayment and those costs are compounded, which can significantly grow the unamortized balance
- **The utility may have to borrow substantial amounts of money in order to finance construction costs.** This high amount of borrowing, combined with the reduced cash flows and delayed repayment of debt or equity returns resulting from the creation of the regulatory asset, can negatively affect the utility's credit rating. A decline in credit rating can make it more difficult and costly for the utility to borrow in the future.
- **It may be difficult to assure the recovery of deferred expenditures in future tariffs.** If costs are expected to rise steadily for several years, the cumulative bill of a series of regulatory assets could become prohibitive, and result in future rate shocks in order to recover the deferred amount.

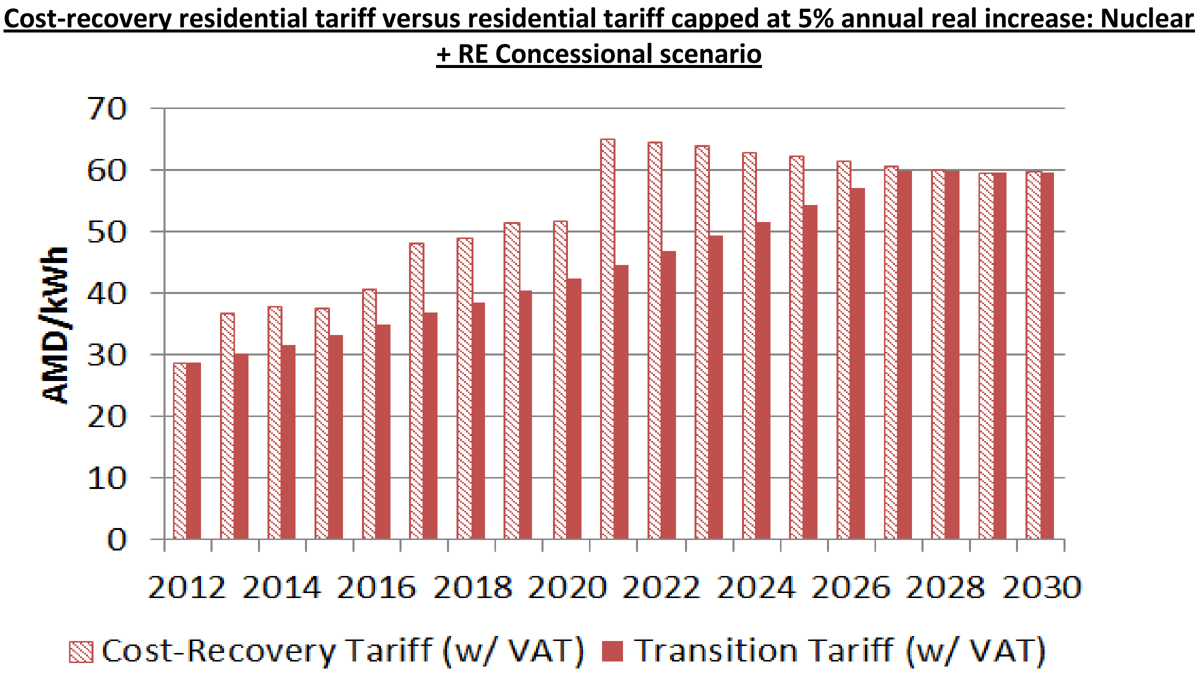
Creating regulatory assets is a commonly used accounting method in the U.S., which uses the Generally Accepted Accounting Principles (GAAP) accounting standards. However, there has been a great deal of international debate and the International Financial Reporting Standards (IFRS) do not yet clearly address the treatment of regulatory assets.

Transitional Subsidy to Cover Revenue Requirement

The Government can also provide a transitional subsidy to smooth out the tariff increase over time. A transitional subsidy is similar to the untargeted full subsidy described in Section 6.1.2 above, but differs in that it is phased out over time. Using a transitional subsidy, the Government places a cap on the annual percentage increase in the tariff for all customers or all customers in class, such as all customers in the residential class. As with the untargeted full subsidy, the transitional subsidy is highly regressive because it provides subsidies to portions of the population that can afford larger tariff increases.

A transitional subsidy can be used in combination with the regulatory mechanisms described above. These regulatory mechanisms are usually a first step to help smooth out the revenue requirement. However, when an unsustainably large single-year tariff increase is expected even with these other mechanisms, the Government may choose to make a policy decision to cap tariff increases for the entire residential population and cover the revenue gap with a transitional subsidy. Figure 6.2 provides an example of how the Government could transition to a cost-recovery tariff in 2027 by initiating a 5 percent real tariff increase annually beginning in 2013.

Figure 6.2: Example of Average Cost-Recovery Tariff versus Transition Tariff



Source: Bank team estimate.

The Government will need to cover the cost of the transition subsidy in order to maintain the financial viability of the sector during the transition period. In the example above showing the Nuclear + RE concessional financing scenario at a 5 percent tariff increase, the net present value (NPV) of the total cost of the transition subsidy is equal to AMD 274 billion or US$ 704 million.

The cost of the transition subsidy will depend on the generation investment scenario as well as the maximum real tariff increase the Government considers reasonable. Table 6.6 shows the NPV of a transitional subsidy under different generation scenarios assuming annual tariff increases of 5, 7 and 10 percent.[34] For some of the lower-cost generation scenarios, the 7 and 10 percent tariff increase beginning in 2013 is too large and would result in an unnecessary surplus of revenue for the sector.

Table 6.6: NPV of Transition Subsidy at Different Levels of Tariff Increase

	NPV of Transition Subsidy Assuming:		
(billion AMD)	5% annual tariff increase	7% annual tariff increase	10% annual tariff increase
Gas concessional	82	-	-
Gas + RE concessional	25	-	-
Nuclear concessional	332	128	-
Nuclear + RE concessional	274	115	14
Gas commercial	133	44	-

[34] A discount rate equal to the average of 12-month LIBOR for 2012 (1.03%) is used to calculate the NPV for the transitional subsidy.

(billion AMD)	NPV of Transition Subsidy Assuming:		
Gas + RE commercial	205	83	18
Nuclear commercial	1,042	666	290
Nuclear + RE commercial	1,242	846	376

6.2.2 Allocating the Revenue Requirement to Customer Classes

After a revenue requirement is established, revenue must be allocated to ensure that costs are fairly distributed across customer classes. As mentioned in Section 4.2.3, class allocation under a marginal cost-based tariff aims to recover costs from, or allocate revenue to, customers in proportion to their contribution to total marginal cost revenues.[35]

Often marginal cost revenue, in other words the revenue that would be recovered if tariffs were set equal to marginal cost, does not equal the revenue required to cover costs and provide a reasonable return on investment. When this occurs, revenue allocated to classes must be adjusted to ensure that under or over collection of revenue does not occur. In practice, regulators use several mechanisms to adjust marginal costs for each customer class to meet the total revenue requirement. These mechanisms vary in the degree to which they preserve efficient price signals and provide another way in which the regulator can help transition from existing tariffs to marginal cost-based tariffs over time.

Using a straight EPMC approach (in which each class' share of the revenue requirement is equal to the class' share of marginal cost revenue) can sometimes create a significant revenue burden for a single class when tariffs have not previously been based on marginal cost. When this is the case, as it is in Armenia, it is acceptable to use a modified approach to EPMC.

A modified approach to EPMC

As described in Section 4.2.3, this study estimated tariffs using both an EPMC and modified EPMC approach. The modified EPMC approach reduces the residential share of the revenue requirement because customer-related costs are a higher share of marginal costs for the residential class than for non-residential customers. The modified EPMC excluding customer costs results in a four percent increase in the residential customer class revenue requirement instead of a 24 percent increase under the straight EPMC approach. The modified EPMC approach helps reduce the burden on the residential class while preserving economic efficiency because customers are least price-sensitive to the fixed components of their bills. Accurate signaling of marginal customer costs is less important for efficient allocation of resources than the price signals for electricity consumption.

Other approaches

Other class revenue allocation possibilities exist when the revenue increase for one class, even using a modified EPMC approach, still produces a significant rate shock for a single class. For example, the regulator can set a specific limit for a class' revenue allocation and use EPMC to spread the remaining revenue requirement proportionally across other classes. Other possible general rules of class revenue allocation include the prescription that no class

[35] As discussed in more detail later, this is known as an EPMC or "equal percentage of marginal cost" allocation. If class elasticities of demand vary significantly, and can be estimated accurately, Ramsey pricing which takes relative class elasticities into account as well may be even more efficient.

should receive a decrease if the overall revenue requirement is increasing and, conversely, no class should receive an increase if the overall revenue requirement is decreasing.

The regulator can gradually bring class revenue allocation to straight EPMC by adjusting the revenue allocation percentages over time. For example, the regulator could begin by first fixing the percentage increase in the revenue allocation to residential customers at a level below EPMC without customer costs. During interim years, this percentage could increase annually until the revenue allocation equals EPMC without customer costs and, potentially, full EPMC.

Regardless of the approach used, it is important for the regulator to ensure rate continuity throughout the transition period. In other words, if the PSRC choses to use transitional steps in approaching EPMC class revenue allocation, it should use class allocation approaches that gradually move the class revenue share towards that target. This must be done in combination with any transitional measures used in the tariff structure so that it provides customers with clear information about what the end-point is expected to be and increases their rates in a clear, understandable way to gradually approach that end-point.

6.2.3 Designing the end-user tariff

The marginal cost-based tariff recommended in Section 4.1 may also cause rate shock. Introducing a seasonal component, removing cross-subsidies that exist between customer classes, and moving to a two-part tariff may significantly affect certain customer groups.

Once the recommended tariff structure is established, transition steps can be taken to adjust the differential between costing periods over time to eventually reflect differences in marginal costs by period. For example, to help ease into high winter per-kWh charges, the PSRC could initially establish a smaller difference between average winter and average summer per-kWh charges and use the marginal cost absolute difference to set the peak and off-peak charges within each season. Or, if introduction of a fixed customer charge is expected to induce large bill impacts for some customers, the PSRC could transition into the marginal cost-based customer charge by initially setting the fixed charge below marginal cost and gradually adjusting upward. As with class allocation, any deviation from marginal cost-based differences in components of the tariff should be avoided unless clear information can be provided to customers about what the end-point and duration of the transition is expected to be.

An alternative to transitions in the tariff structure itself is to provide billing plans that allow customers to smooth out payment over the course of the year. This type of billing arrangement charges the customer an estimated average monthly bill by estimating the customer's annual bill and dividing by 12. Any deviations from the estimated annual bill are either charged or refunded at the end of this year. This takes care of any cash flow problems customers may incur during high cost months when their bills would be highest. It also maintains price signals as the bill shows the actual costs incurred each month (in addition to the levelized amount due).[36]

[36] Commission for Energy Regulation. "Electricity Tariff Structure Review: Alternative Tariff Structures. A Consultation Paper." CER/04/239. 1 July 2004.

7 Conclusions and Recommendations

Financial sustainability of the power sector is important, however, it is equally important to consider affordability of electricity and put in place necessary safety nets to protect the socially vulnerable consumers. With large investment needs facing the energy sector over the next ten years, it is important that policymakers look carefully at how to best protect poor households from tariff increases that will inevitably be needed to maintain efficient and reliable electricity service.

Tariffs in combination with social assistance measures provide two key policy and regulatory tools for sustaining the financial viability of the energy sector while maintaining energy affordability for the population. Tariffs for residential customers need to increase roughly 15 percent to cover the gap that has developed in recent years between the efficient cost of service and the average tariff collected from customers.

Over the next ten years, tariffs will need to continue to increase to cover the cost of new investments. The generation option selected to replace the nuclear plant will have a large impact on how much end-user tariffs need to increase. In particular, the average residential tariffs will need to increase by 69 percent if Armenia builds a gas plant with concessional financing and as much as 286 percent if Armenia builds a nuclear plant and renewable energy plants with commercial financing. The following subsections describe how the Government can improve the financial sustainability of the sector, mitigate rate shock, and maintain affordability amidst the large tariff increases that are expected in the next ten years.

Improving Financial Sustainability

The Government can take the following steps to improve the financial sustainability of the sector:

- **Develop and follow a least cost investment plan**. Identifying the least-cost generation option for serving the next unit of energy or demand can help ensure that the revenue requirement does not exceed the reasonable and efficient cost of electricity service provision. This is also the first step in developing marginal cost-based tariffs for electricity. Decisions to build plants that are not least-cost or that do not bring other marginal benefits to offset those costs distort efficient price signals for consumers and make electricity service unnecessarily expensive.
- **Implement a marginal cost-based tariff structure**. The marginal cost-based tariff in Armenia includes:
  - *A seasonal component* reflecting the higher energy and capacity costs of providing electricity service during winter peak hours
  - *A fixed monthly component* reflecting costs that are incurred based on the number and location of customers.
  - *Improved allocation of revenue to customer classes* so as to reflect each class' contribution to marginal costs.

Mitigate Rate Shock

Moving to marginal cost-based tariffs may lead to large increases in bills for certain groups of customers, particularly in the residential class. In the short-term, these increases are less significant, but may adversely affect household bills during winter months when winter peak tariffs are higher than existing tariffs. The following principles can support a transition to marginal cost-based tariffs that is clear and understandable to end-users and also avoids rate shock in a single year:

- **Establish time-differentiated rate structure with seasonal and time-of-day components immediately.** Frequent adjustments to the tariff structure reduce rate continuity and make it difficult for customers to understand and therefore react to price signals. For this reason, when transitioning to marginal cost-based tariffs, it is best to establish the desired tariff structure immediately, even if the levels of those charges must deviate from marginal costs in order to meet other tariff objectives.
- **Adjust class allocation and components of rate structure to gradually approach marginal cost price signals**. The PSRC can choose to adjust differentials between components of the tariff structure over time. For example, to help ease into high winter per-kWh charges, the PSRC could initially establish a smaller difference between average winter and average summer per-kWh charges and use the marginal cost absolute difference to set the peak and off-peak charges within each season. Or, the PSRC could first use a class allocation mechanism of EPMC without customer charges to reduce the impact on the residential class. If these transition mechanisms are used, it is important to give customers clear information on the end-point of the transition.
- **Allow for flexibility in billing.** Allowing for flexible billing plans can maintain marginal cost price signals while avoiding cash flow problems that customers may incur during winter months when bills are highest.
- **Use regulatory mechanisms to smooth out large increases in the sector revenue requirement over several years.** New investments in generation to replace the ANPP will require large tariff increases regardless of whether or not a marginal cost-based tariff structure is in place. The PSRC can help mitigate rate shock in a single year by allowing companies to utilize the regulatory accounting principle, Construction Works in Progress, which can significantly reduce the single year tariff increase that would be required to keep tariffs at cost-recovery levels.

In some cases even with these measures, the Government may consider the single-year tariff increase that would result from investment in new generation to be too high for residential customers. If this occurs, the Government may also consider capping the annual tariff increase for residential customers and providing a subsidy to cover the revenue gap. This approach should be considered as a last resort, however, given the large fiscal cost of such a subsidy program—particularly for higher-cost generation investment scenarios.

Maintaining Affordability

Even with transition mechanisms to avoid rate shock, some customers will not be able to afford the full cost of service once investments in new generation are included in the tariff. Thus, the Government will need to undertake measures to ensure adequate protection of the socially vulnerable customers.

Table 7.1 shows the comparison of subsidy delivery options available to the Government.

Table 7.1: Comparison of Electricity Subsidy Delivery Options[37]

	Economic Distortion[1]	Fiscal Cost		Coverage				Targeting			Sum of Individual Ranks	Final Rank
	Rank	bln AMD	Rank	Total	Non-Poor	Poor	Rank	Non-Poor	Poor	Rank		
Voucher Program/Cash Transfer to All Poor Households	1	1.5-14.5	3	15%	0%	98%	1	0%	100%	1	6	1
Partial subsidy cash transfer/voucher (30 percent discount) for FB beneficiaries	3	1.4-3.6	2	13%	8%	43%	4	55%	45%	3	12	2
Lifeline tariffs - Increasing Block Tariff for FB beneficiaries	5	1.4-3.3	1	13%	8%	43%	4	55%	45%	2	12	2
Voucher Program/Cash Transfer to FB beneficiaries	1	1.6-14.8	4	13%	8%	43%	4	60%	40%	4	13	4
Lifeline tariffs - Increasing Block Tariff for all customers	6	12.3-75.7	6	98%	98%	98%	1	88%	12%	6	19	5
Lifeline tariffs - Volume Differentiated Tariff for all customers	4	2.7- 60.8	5	19%	17%	34%	7	82%	18%	5	21	6
Reduced tariff for all customers	7	24-147	7	98%	99%	98%	1	90%	10%	7	22	7

[1]Economic distortion rank based on team's qualitative evaluation of subsidy options.

[37] The table contrasts different theoretical options to ensure protection of vulnerable customers based on either targeted or universal measures. For the sake of simplicity, targeted interventions are modeled based on the existing Family Benefit project and its targeting mechanism. In depth analysis of the PFBP program, and its targeting mechanism would be needed before a targeted program such as the ones simulated in the table could be implemented. Subsidy options were evaluated and ranked 1-7 in terms of economic distortion, fiscal cost, coverage and targeting efficiency. A rank of 1 corresponded to the best evaluation in each category and a rank of 7 corresponded to the worst evaluation. For example, the subsidy option with the lowest cost received a rank of 1. The individual ranks for each subsidy option were then summed giving equal weight to each evaluation category. The subsidy option with the lowest overall sum was then considered the best subsidy delivery option across all four categories.

Appendix A: Estimating Revenue Requirement—Key Assumptions and Results

The revenue requirement was estimated based on our assessment of the efficient cost of service for generation, transmission, and distribution. The revenue requirement was projected through 2030 based on the eight investment scenarios described in the Armenia Energy Sector Note (2011). However, some of the assumptions related to plant size, expected start date, dispatch, loan terms, and demand were updated based on new information provided by the PSRC and the system operator.

The revenue requirement was estimated taking into account the cost of existing generation, transmission, and distribution and the projected cost of generation for new plants. Total variable costs for existing and new plants were estimated based on a generation forecast developed from our simulation of dispatch. Section A.1 explains how dispatch of power plants was simulated to meet demand. Section A.2 describes how costs of existing plants were estimated and provides details on these costs. Section A.3 describes the assumptions used to estimate costs for new plants based on the Armenia Energy Sector Note (2011).

A.1 Dispatch Simulation

A model was created to simulate the dispatch of Armenia's electricity system to meet demand. The model simulated an hourly dispatch of plants required to meet demand from 2011 through 2030.

An hourly demand curve for 2011, obtained from the system operator, was used as the basis for the initial load shape. Demand in each hour of each day of each year was multiplied by the compound electricity consumption growth forecasted through 2030.[38] Peak load and electricity consumption are assumed to grow at the same pace during this time period.

The supply curve was created using the plants in Appendix Table A.1. Maximum utilization factors were chosen based on known technical specifications of the plants.

[38] Based on demand forecast developed in "Charged Decisions: Difficult Choices in Armenia's Energy Sector." World Bank. October 2011, updated to reflect changes in GDP growth in 2011

Appendix Table A.1: Sources of Supply

Plant Name	Dependable Capacity (MW Net)	Maximum Utilization Factor[39]	Dispatch Order (1=first dispatched)	First Year of Operation (in the planning period)	Last Year of Operation (in the planning period)
New Nuclear Plant	1023	1	1	2021	2030
ANPP	385	1	2	2010	2020
Sevan-Hrazdan HPP	431	1	3	2010	2030
Existing Small Hydro	174	0.3	4	2010	2030
Small HPP1	38.05	0.3	5	2012	2030
Small HPP2	38.05	0.3	6	2013	2030
Small HPP3	38.05	0.3	7	2014	2030
Small HPP4	38.05	0.3	8	2015	2030
Vorotan	404	1	9	2010	2030
Yerevan CCGT	216	1	10	2010	2030
New Gas Plant	800	1	11	2021	2030
Lori-Berd HPP	66	0.36	12	2017	2030
Shnokh HPP	70	0.5	13	2017	2030
Wind	175	0.3	14	2017	2030
Meghri HPP	140	0.68	15	2019	2030
Hrazdan 5	396	1	16	2010	2030
Hrazdan TPP	850	1	17	2010	2020

Certain generators had seasonal or dispatching constraints that were also reflected in the model:

- ANPP is stopped for routine maintenance twice a year: 10 days in May; 45 days in September-October, except every fourth year when the plant is stopped for 80 days beginning in September.
- There are seasonal, irrigation-related constraints for the Sevan-Hrazdan cascade. The analysis reflects this by limiting production in any hour at historic average monthly capacity factors for the plant.
- Vorotan also has a pattern of dispatch which is highly seasonal. We simulated Vorotan's dispatch by limiting production in any hour at levels generated in 2008. The 2008 data are sample days (the 16th) from each month of 2008.

[39] This is a limit placed on the production of each plant, during each hour, for the purpose of determining a level of annual generation which is consistent with the plant's net dependable capacity (as defined in Appendix A and B). This limit applies to generation only, not to availability during peak periods.

Plants in service were dispatched in the order indicated in

Appendix Table A.1.

Appendix Table A.2 indicates the plants in service in each of the eight investment scenarios. For each hour of each day of the planning period, the plants that were in-service during that year and season were added to the supply curve until supply equaled demand.

Appendix Table A.2: Plants in Service under Eight Investment Scenarios

	Concessional				**Commercial**			
Plant Name	**Gas only**	**Gas + RE**	**Nuclear only**	**Nuclear + RE**	**Gas only**	**Gas + RE**	**Nuclear only**	**Nuclear + RE**
New Nuclear Plant			X	X			X	X
ANPP	X	X	X	X	X	X	X	X
Sevan-Hrazdan HPP	X	X	X	X	X	X	X	X
Existing Small Hydro	X	X	X	X	X	X	X	X
Small HPP1		X		X		X		X
Small HPP2		X		X		X		X
Small HPP3		X		X		X		X
Small HPP4		X		X		X		X
Vorotan	X	X	X	X	X	X	X	X
Yerevan CCGT	X	X	X	X	X	X	X	X
New Gas Plant	X	X			X	X		
Lori-Berd HPP		X		X		X		X
Shnokh HPP		X		X		X		X
Wind		X		X		X		X
Meghri HPP	X	X	X	X	X	X	X	X
Hrazdan 5	X	X	X	X	X	X	X	X
Hrazdan TPP	X	X	X	X	X	X	X	X

The dispatch simulation also accounted for exports to Iran based on our understanding of the terms of the gas-electricity swap (see Box 2.1). Appendix Table A.3 shows the level of export by year we used in the dispatch model and how and why this differed in certain years from the information on planned exports provided by the system operator.

Appendix Table A.3: Export Assumptions used in Dispatch Model

Year	Exports Planned – System Operator (kWh)	Exports Assumed in Dispatch Model (kWh)	Reason for Difference
2011	1,382,780,000	1,382,780,000	---
2012	1,399,000,000	1,399,000,000	---
2013	2,200,000,000	2,200,000,000	---
2014	5,400,000,000	4,029,000,000	Capped at maximum generation of Yerevan CCGT and Hrazdan 5 based on assumption that gas must be used for electricity generation at cost-effective plants and cannot be used for other purposes (e.g. domestic consumption)
2015	5,400,000,000	4,029,000,000	
2016	5,400,000,000	4,029,000,000	
2017	5,400,000,000	4,029,000,000	
2018	5,400,000,000	4,029,000,000	
2019	5,400,000,000	4,029,000,000	
2020	5,400,000,000	4,029,000,000	
2021-2030	7,500,000,000	5,361,120,000	Capped by transmission capacity of new 400 kV line

Source: Information from System Operator; Bank team assumptions.

Exports were expected to take place during the hours of the year with lower domestic load, reflecting our understanding of the export arrangement under which Armenia can send electricity to Iran during off-peak hours.

The export arrangements were modeled by first calculating the spare capacity of each plant, during each hour, after domestic demand had been served (using the dispatch simulation described above). We assumed that the aggregate volume of exports for each year (for example, 1.399 GWh in 2012) would first be served from plants which i) had spare capacity, and ii) were lowest in the dispatch order. Spare capacity from plants higher in the dispatch order was used to serve exports only once the spare capacity from the plants lowest in the dispatch order was exhausted. For example, Yerevan CCGT was not dispatched to meet export demand until all of the spare capacity of ANPP had been exhausted for the year.

In deciding how to allocate export demand to the spare capacity of a certain plant (for example Yerevan CCGT), export demand was first allocated to hours in which there was less spare capacity to reflect the fact that export demand will likely first be served by smaller increases in generation from plants that are already running at some level.

The benefit of exports was accounted for by excluding fuel costs for first Yerevan CCGT and then Hrazdan 5 for the equivalent of 1.5 times the kWh exported. This reflects the fact that for every 1 cubic meter of gas imported from Iran, 4.5 kWh are generated. According to the swap agreement, an assumption was made that 3 kWh are exported for every 1 cubic meter of gas imported, however, our dispatch model allows for those exports to be met by cheaper, non-thermal plants if capacity is available. By modeling this way, we assumed that Armenian customers would receive more than the 1.5 kWh of excess electricity generated from Iranian gas that remains in the domestic market.

A.2 Costs for Existing Companies

The following subsections show the data used and assumptions made to estimate:

- Operations and maintenance (O&M)
- The regulatory asset base, used to calculate the depreciation and profit components of tariffs for existing plants
- Debt service on concessional loans provided to existing plants.

A.2.1 Operations and Maintenance

Appendix Table A.4 shows O&M costs broken out by cost category for transmission, dispatch and settlement. We have assumed that the O&M costs included in the PSRC's tariff calculations for 2012 reflect the full cost of operations and maintenance. The majority of O&M costs for these companies are fixed, in other words, they do not vary significantly with increases or decreases in consumption. While the monthly fee received by the settlement center and dispatcher reflect the fixed nature of these costs, HVEN recovers these costs on a per kWh basis. Notably, the PSRC's tariff worksheet for ENA does not breakout O&M costs by category. However, at an estimated 23,323 million AMD, given the PSRC's consumption forecast for 2012, these costs represent more than 55 percent of ENA's total cost of service.

Appendix Table A.4: O&M Costs for Transmission, Dispatch, and Settlement in 2012

mln AMD	HVEN	Settlement	Dispatch
Material expenses	170	5	76
Repairs	400	-	17
Salary	924	65	407
Social payments	176	10	70
Other expenses	80	21	81
Annual license fee	15	5	5
Preparation of documents/reports	-	8	8
Regulatory fee	6	-	1
Electric setting expenses	18	-	-
Total O&M Expenses	1,789	115	3,811

Source: PSRC.

Appendix Table A.5 shows O&M costs broken out by cost category for generation companies. As the table shows, variable costs consist primarily of fuel costs plus some material and repair expenses. Salaries, social payments, material expenses, repairs and other expenses represent the remaining fixed O&M for all plants.[40] Fuel costs are excluded from the O&M cost breakdown for Yerevan CCGT because of the gas-electricity swap that the Government of Armenia has negotiated with the Government of Iran.

[40] The PSRC tariff worksheet for Hrazdan 5 showed all O&M costs as variable because the plant was still undergoing testing. We have adjusted non-fuel O&M to be considered fixed costs to reflect the fact that the plant is fully operational after 2012.

Appendix Table A.5: Operations and Maintenance Costs for Generators

mln AMD	Hrazdan TPP (old)		Hrazdan 5		Yerevan CCGT		Sevan-Hrazdan Cascade		Vorotan		ANPP	
	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed
Fuel expenses	5,327	-	23,832	-	-	-	-	-	-	-	9,597	-
Maintenance of unused assets	-	339	-	-	-	-	-	-	-	-	-	-
Payment for transmitted natural gas	-	-	-	-	-	2,140	-	-	-	-	-	-
Materials expenses	-	155	-	484	-	242	-	181	-	84	155	618
Repairs	-	501	-	1,572	-	786	-	449	135	135	-	1,654
Salary	-	880	-	514	-	171	-	519	-	279	-	3,112
Social payments	-	167	-	99	-	33	-	99	-	53	-	467
Other expenses	-	199	-	45	396	346	-	187	-	101	-	517
Annual license fee	-	15	-	15	-	15	-	15	-	15	-	17
Preparation of documents/reports	-	-	-	-	-	14	-	3	-	-	-	-
Regulatory fee	-	11	-	-	-	6	-	3	-	7	-	24
Purchased electricity	-	188	-	50	-	17	-	112	-	70	271	155
Electric setting expenses	-	23	-	50	-	40	-	6	-	73	-	80
Other nuclear expenses	-	-	-	-	-	-	-	-	-	-	-	3,478
Total O&M Expenses	5,327	2,478	26,661	-	396	3,811	-	1,573	135	816	10,022	10,123

Source: PSRC.

Note: Total variable costs based on PSRC forecast of generation for 2012.

A.2.2 Regulatory Asset Base

Appendix Table A.6 shows information on the historic and residual value of assets for each company, and the depreciation rates and rates of return approved by the PSRC. A rate base is not used in estimates of the revenue requirements of the following three plants:

- Yerevan Combined Cycle Gas Turbine (CCGT) is a new plant that has been 100 percent financed with a concessional loan from the Japanese Government and is, therefore, not included in the regulatory asset base
- Armenia Nuclear Power Plant (ANPP) is assumed to be fully depreciated
- The owner of Hrazdan 5 has negotiated a different methodology than specified in the PSRC's generation tariff methodology for recovering a return on investment.

Appendix Table A.6 therefore excludes Yerevan CCGT, ANPP, and Hrazdan 5.

Appendix Table A.6: Inputs Used to Estimate Depreciation and Profit in 2012

Company		Historic Asset Value	Residual Asset Value	Annual Depreciation Rate	Annual Rate of Return on Assets
		bln AMD	*bln AMD*	*%*	*%*
Hrazdan TPP (old)		16.1	1.61	4%	10%
Vorotan		126.8	27.5	3.7%	10%
Sevan-Hrazdan Cascade		3.5	3	3.3%	10%
HVEN		93.3	4.3	4%	10%
ENA	Privatized Assets[a]	23.16	0.883	10%	17%
	Investments since 2004	69	60	4%	17% - pre-2009 12% - post-2009
Settlement Center[b]		374.6	13	4%	10%
System Operator[b]		1456	53	4%	10%

Source: PSRC

[a] Based on initial purchase price of US$ 40 mln at 2003 average exchange rate of 579 AMD/USD and residual value of US$ 2.33 mln at 2012 exchange rate of 279 AMD/USD.

[b] Actual asset values not provided by PSRC; Values in table are calculated based on profit and depreciation included in PRSC's 2012 tariff worksheet.

The estimate of the rate base for the next few years includes near-term investments planned by the energy companies and approved by PSRC. No electricity company has formally submitted an investment program for the 2013-2017 time period, but the PSRC investment department indicated that it expects to approve the following investment programs:

- US$ 10 million annually (3.8 billion AMD) for investments in the rehabilitation of Sevan-Hrazdan Cascade over the next five years

- US$ 20 million annually (7.8 billion AMD) for investments in rehabilitation and replacement of existing assets and new connections for ENA over the next three years.

We have assumed that these investments are included in the rate base of each company, and therefore earn a return, and incur depreciation charges. The PSRC does not expect any of the other energy companies to make investments from non-concessional sources of financing in the next few years.

A.2.3 Debt Service Costs for Concessional Loans

Two energy companies have secured concessional loans for investments:

- **Vorotan Cascade**. Vorotan has received a loan in the amount of US$71 million from KfW to finance reconstruction and replacement of equipment the three hydropower plants. The initial portion of the loan (US$40 million) was obtained through an agreement on financial cooperation between Armenia and Germany signed in 2007-2008. The second portion (US$31 million) was obtained through an agreement reached in July of 2011. The project was launched in 2011.[41]
- **HVEN**. The High Voltage Electricity Network (HVEN) has obtained a loan in the amount of US$39 million from the World Bank to finance replacement of 230 km of transmission line from the Hrazdan Thermal Power Plant to Vorotan Cascade of hydro power plants. The loan was approved in May 2011. The total cost of the project is US$52 million, of which US$13 million will be financed by the Government of Armenia.[42]

Appendix Table A.7 shows the projected annual debt service requirements based on the terms of each of these loans.

Appendix Table A.7: Annual Debt Service Requirements for Concessional Loans

		Vorotan		HVEN
	Units	KfW - 1st tranche	KfW - 2nd tranche	WB
Investment Cost	mln US$	40	31	39
Interest Accrued During Grace Period	mln US$	8.8	1.3	18.7
Interest Rate	%	2%	2%	4%
Maturity	# of years	40	15	25
Grace Period	# of years	10	2	10
Year of Disbursement	year	2007	2011	2011
Annual Debt Service	mln US$	$2.18	$2.84	$5.19
Annual Debt Service	mln AMD	825	1,077	1,968

Source: See Footnotes 41 and 42; Bank team estimats.

41 "Armenia will borrow $71 mln from Germany to modernize Vorotan Cascade." Invest in Armenia. https://sites.google.com/site/investinarmenia/news-3 Accessed: 19 April 2012

42 "World Bank Provides US$ 39 Million to Strengthen Power Supply Reliability in Armenia." World Bank Press Release. http://go.worldbank.org/YSMFPVYU80 Accessed: 19 April 2012

A.3 Costs for New Plants

The revenue requirements for new plants were estimated based on the following assumptions:

- *Plant costs.* Armenia's Least Cost Generating Plan (LCGP), internal World Bank estimates, and international industry benchmarks were used as sources for estimates of capital costs, variable O&M, fixed O&M, and decommissioning costs (for the nuclear plant).
- *Asset life* (different for each plant).
- *Loan tenures.* Twenty-year loan terms for all new plants, except for Yerevan CCGT, which has a 40 year loan from the Japanese Government.
- *Cost of capital* (cost of debt and equity). The cost of debt was assumed to be 10.39 percent for commercial financing and 3 percent for concessional financing. The cost of equity was assumed to be 18 percent. Two scenarios were simulated for the structure of financing: (i) all-debt financing ("concessional financing"); and (ii) 70/30 debt/equity mix ("commercial financing").
- *Corporate tax.* The model assumes 20 percent corporate tax in all cases.
- *Load factor.* The load factor depends on the level of plant operation required to meet forecast demand (which depends on the dispatch hierarchy). If the plant is lower in dispatch hierarchy (dispatched later, for economic reasons), and demand is low, the plant has a lower load factor. The load factor for each plant was estimated from the dispatch model.

Appendix Table A.8 provides detail on cost assumptions for potential new power plants, including capital costs, variable O&M, and fixed O&M.

Appendix Table A.8: Cost Assumptions about New Power Plants

Plant	Capital Costs ($/kW)	Variable O&M ($/kWh)	Fixed O&M (S$/kW/year)
Hrazdan 5	505	0.87	14
Yerevan CCGT	1,123	0.96	15.04
New Gas Plant	1,140	0.87	14
New Nuclear Plant*	5,500	0.2	53.4
Meghri HPP	1,643		13.9
Shnokh HPP	1,818.2		10.1
Lori-Berd HPP	1,818.2		13.9
Small HPPs	1,000		12
Wind	1,500		12

*Decommissioning costs for: new nuclear plant = US$ 330.5 million; ANPP = US$ 250 million.

A.4 Revenue Requirement for 2013-2030

Appendix Table A.9: Revenue Requirement — New Gas with Commercial Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	80,717	92,364	106,499	109,595	123,433	116,919	116,847	96,479	106,596	188,169
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	130,356	140,895	153,814	157,647	171,847	166,017	166,601	146,863	157,066	238,920
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	24	26	28	28	30	28	28	24	26	39
Average Tariff w/ VAT (20%)	29	31	33	33	36	34	34	29	31	46

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	188,697	189,238	189,792	190,349	190,924	191,520	192,139	192,166	191,999
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	241,169	242,231	242,997	244,021	245,036	246,047	247,053	247,439	247,605
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	38	38	38	37	37	36	36	36	35
Average Tariff w/ VAT (20%)	46	46	45	45	44	44	43	43	42

Appendix Table A.10: Revenue Requirement — New Gas with Concessional Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	77,091	87,186	95,965	99,064	112,927	106,396	106,328	86,531	106,596	151,008
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	126,730	135,717	143,280	147,116	161,342	155,493	156,082	136,915	157,066	201,759
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	23	25	26	26	28	27	26	23	26	33
Average Tariff w/ VAT (20%)	28	30	31	31	34	32	32	27	31	39

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	151,212	151,423	151,643	151,868	152,107	152,363	152,637	152,639	152,561
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	203,683	204,416	204,848	205,540	206,220	206,889	207,550	207,912	208,167
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	32	32	32	31	31	31	30	30	30
Average Tariff w/ VAT (20%)	39	38	38	38	37	37	36	36	35

Appendix Table A.11: Revenue Requirement — New Gas + RE with Commercial Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	82,298	94,449	108,114	109,125	119,704	124,678	122,216	114,293	130,524	213,881
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	131,937	142,980	155,429	157,178	168,118	173,776	171,970	164,677	180,994	264,632
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	24	26	28	28	29	30	29	27	30	43
Average Tariff w/ VAT (20%)	29	31	33	33	35	36	35	33	36	51

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	213,791	213,702	213,612	213,523	213,433	213,344	213,704	214,426	215,162
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	266,263	266,695	266,817	267,195	267,546	267,871	268,617	269,699	270,768
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	42	42	41	41	40	40	39	39	38
Average Tariff w/ VAT (20%)	51	50	49	49	48	48	47	47	46

Appendix Table A.12: Revenue Requirement — New Gas + RE with Concessional Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	76,692	86,656	92,756	93,457	103,580	100,699	97,834	92,794	87,461	164,950
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	126,331	135,187	140,071	141,510	151,994	149,796	147,588	143,178	137,932	215,701
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	23	25	25	25	26	26	25	24	23	35
Average Tariff w/ VAT (20%)	28	30	30	30	32	31	30	29	27	42

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	164,861	164,771	164,682	164,592	164,503	164,414	164,514	164,766	165,026
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	217,332	217,765	217,886	218,264	218,616	218,940	219,427	220,040	220,632
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	35	34	34	33	33	32	32	32	31
Average Tariff w/ VAT (20%)	41	41	40	40	39	39	38	38	38

Appendix Table A.13: Revenue Requirement — New Nuclear with Commercial Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	80,505	92,286	107,234	110,342	124,261	117,694	117,636	97,100	105,572	447,727
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	130,144	140,817	154,549	158,395	172,675	166,791	167,390	147,483	156,042	498,479
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	24	26	28	28	30	29	28	25	26	80
Average Tariff w/ VAT (20%)	29	31	33	34	36	34	34	29	31	97

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	447,992	448,264	448,540	448,812	448,779	448,689	448,600	448,510	448,421
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	500,464	501,257	501,744	502,484	502,891	503,216	503,513	503,783	504,027
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	80	79	78	77	75	74	73	72	71
Average Tariff w/ VAT (20%)	96	94	93	92	91	89	88	87	86

Appendix Table A.14: Revenue Requirement — New Nuclear with Concessional Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	77,815	88,258	97,993	101,079	114,855	108,382	108,299	88,479	106,869	230,268
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	127,454	136,789	145,308	149,132	163,269	157,480	158,053	138,863	157,340	281,020
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	24	25	26	26	28	27	27	23	26	45
Average Tariff w/ VAT (20%)	28	30	31	32	34	32	32	28	31	54

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	230,606	230,952	231,303	231,650	231,628	231,538	231,449	231,359	231,270
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	283,078	283,945	284,507	285,322	285,740	286,065	286,362	286,633	286,876
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	45	45	44	43	43	42	42	41	41
Average Tariff w/ VAT (20%)	54	53	53	52	51	51	50	49	49

Appendix Table A.15: Revenue Requirement — New Nuclear + RE with Commercial Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	83,116	95,292	108,962	109,974	120,561	154,831	152,369	144,450	160,667	452,296
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	132,755	143,823	156,277	158,026	168,975	203,929	202,123	194,833	211,137	503,047
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	25	26	28	28	29	35	34	32	35	81
Average Tariff w/ VAT (20%)	29	31	34	33	35	42	41	39	42	97

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	452,669	453,049	453,435	453,818	454,207	454,603	455,007	457,563	465,397
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	505,141	506,042	506,639	507,490	508,319	509,130	509,920	512,836	521,003
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	80	79	78	77	76	75	74	74	74
Average Tariff w/ VAT (20%)	96	95	94	93	92	90	89	89	89

Appendix Table A.16: Revenue Requirement — New Nuclear + RE with Concessional Financing

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Generation (mln AMD)	78,792	89,467	97,041	97,737	107,644	130,981	128,165	122,707	115,957	232,594
Settlement Center	132	117	117	117	117	117	117	117	117	117
System Operator	1,375	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	6,124	5,562	3,595	3,595	3,246	3,246	3,246	3,246	2,731	2,436
Distribution	42,009	41,535	42,287	43,024	43,735	44,418	45,075	45,704	46,307	46,882
Total Revenue Requirement	128,431	137,998	144,356	145,789	156,058	180,078	177,919	173,091	166,428	283,345
Net Generation (mln kWh)	6,294	6,394	6,491	6,591	6,692	6,794	6,898	7,000	7,103	7,208
Transmission Losses										
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	120	121	123	125	127	129	131	133	135	137
Electricity supplied to distribution grid (million kWh)	6,175	6,272	6,368	6,466	6,565	6,665	6,767	6,867	6,968	7,071
Distribution Losses										
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	766	778	790	802	814	826	839	852	864	877
Electricity Consumption	5,409	5,494	5,578	5,664	5,751	5,839	5,928	6,015	6,104	6,194
Average Tariff	24	25	26	26	27	31	30	29	27	46
Average Tariff w/ VAT (20%)	28	30	31	31	33	37	36	35	33	55

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation (mln AMD)	232,967	233,346	233,733	234,115	234,504	234,901	235,304	237,004	241,881
Settlement Center	117	117	117	117	117	117	117	117	117
System Operator	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316	1,316
Transmission	3,608	3,608	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Distribution	47,431	47,953	48,447	48,915	49,356	49,770	50,156	50,516	50,849
Total Revenue Requirement	285,439	286,340	286,937	287,787	288,617	289,427	290,217	292,278	297,487
Net Generation (mln kWh)	7,315	7,423	7,532	7,641	7,751	7,863	7,976	8,091	8,208
Transmission Losses									
percent (%)	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
million kWh	139	141	143	145	147	149	152	154	156
Electricity supplied to distribution grid (million kWh)	7,176	7,282	7,389	7,496	7,604	7,713	7,825	7,938	8,052
Distribution Losses									
percent (%)	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%	12.40%
million kWh	890	903	916	929	943	956	970	984	998
Electricity Consumption	6,286	6,379	6,473	6,566	6,661	6,757	6,854	6,953	7,054
Average Tariff	45	45	44	44	43	43	42	42	42
Average Tariff w/ VAT (20%)	54	54	53	53	52	51	51	50	51

Appendix B: Estimating Marginal Costs and Determining Marginal Cost-Based Tariffs

This Appendix describes how the marginal costs were estimated and uses those estimates to determine a marginal cost-based tariff structure. Section B.1 describes the conceptual approach to developing marginal cost-based tariffs. Section B.2 describes selection of costing/pricing periods. Sections B.3 to B.5 describe in further detail how each component of marginal cost was estimated. Section B.6 describe how working capital, losses, and economic carrying charges were estimated—key inputs for estimating marginal costs for all four components. Finally, Section B.7 summarizes marginal cost results for 2013-2021.

B.1 Conceptual Approach

There are several different marginal cost concepts. The *long-run* marginal costs are defined as marginal costs associated with a system that is in load-resource balance; i.e., that has neither excess nor insufficient capacity. Technically, in the long-run all factors of production are variable, so that system planners and operators have full flexibility to reoptimize the system in response to changes in load. This report provides approximations of long-run marginal generation costs, but also provides estimates of *short-run* annual marginal generation costs, for the period 2013 – 2021, that reflect the excess capacity and deficient reserve margins expected in some of those years. Because load forecasting is an imperfect science and capacity must often be added in discrete chunks rather than smoothly as load grows, electric systems often have more or less capacity than is optimal. As in most marginal cost studies of the electric industry, estimated marginal transmission and distribution costs are *long-term* marginal costs that reflect the typical investment in transmission and distribution equipment over the budget period in response to load growth, but do not specifically assume optimality.

The approach to determining the marginal cost of electricity is to examine the system planners' and operators' response to load changes at different times of the day and year. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurement can be made. The costs we measure to develop the marginal cost of electricity service include:

- **Marginal generation costs**. This includes capacity costs reflecting the cost of additional capacity to meet an additional unit of peak load growth (kW) and energy costs reflecting the cost in a given hour of producing an additional unit of energy (kWh) from the marginal plant.
- **Marginal transmission costs.** This includes the cost of transmission investments designed to meet an additional unit of load growth and operation and maintenance (O&M) expenses associated with the additional transmission capacity.
- **Marginal distribution costs.** This includes the cost of subtransmission, distribution substation and feeder capacity added to serve an additional unit of load growth and O&M expenses associated with the additional distribution capacity.

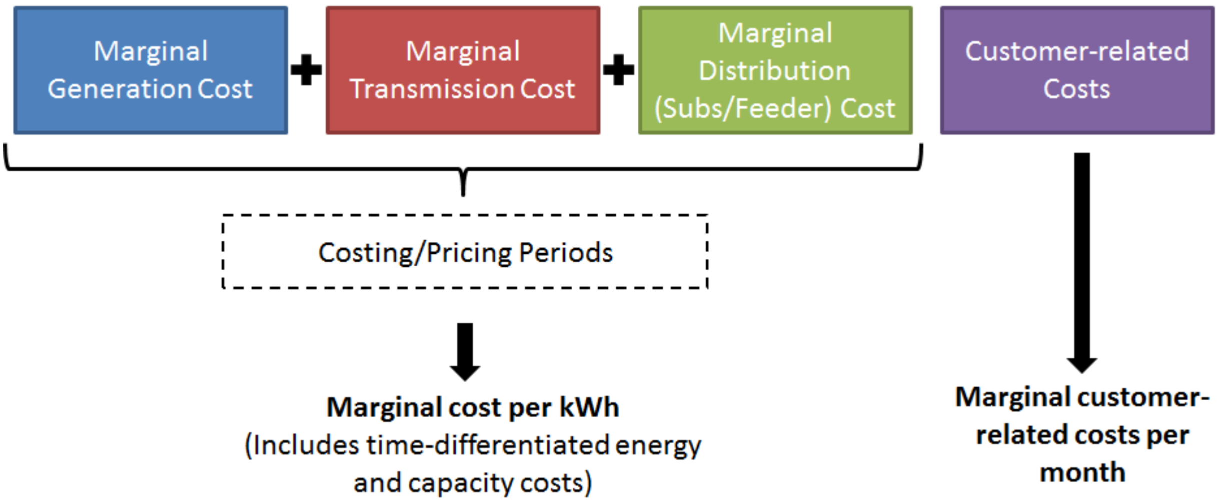
- **Customer-related costs.** This includes the cost of meters and local facilities (service drops, secondary lines, secondary transformers, etc.) and customer-related O&M required to serve an additional customer.

Marginal energy costs vary by hour due to differences in loads and generator availability. Marginal capacity costs also vary by hour. The annualized costs of investment needed to meet additional peak demand on each system component are assigned to hours of the year using a measure of the relative likelihood that load growth in an hour will trigger the need for additional capacity.

For each hour of a typical weekday and weekend day in each month, marginal generation, transmission, and distribution costs are summed and the hourly totals are analyzed to identify appropriate costing/pricing periods. The marginal costs per kWh for each costing/pricing period and year are based on the weighted average of hourly marginal generation, transmission, and distribution costs during each period. The marginal cost of electricity service includes these per-kWh costs and customer-related costs for each customer class, estimated on a monthly basis.

Appendix Figure B.1 depicts this methodological framework for estimating marginal costs.

Appendix Figure B.1: Methodological Framework for Estimating Marginal Costs



The use of marginal costs in allocating the total revenue requirement to customer classes, setting levels for the various charges, and defining the differentials in usage charges by pricing periods can enhance the economic efficiency of the tariffs. Such tariffs provide price signals that help consumers make efficient energy decisions and help to ensure that the system's design and operation is not wasting resources.

Typically the total revenue requirement to be recovered by end-user tariffs is not based on marginal costs, but rather on providing a reasonable return on investment to the various electricity sector participants. Thus, marginal unit costs per kW, per kWh and per customer cannot be charged directly as rates, but must be adjusted to produce the appropriate total revenue. These adjustments can be made in a manner that preserves, as much as possible, the efficient price signals.

In Section B.8, we develop proposed end-user tariff structures based on marginal cost results summarized in Section B.7 and that recover the revenue required to provide a reasonable return on investment to all electricity service providers.[43]

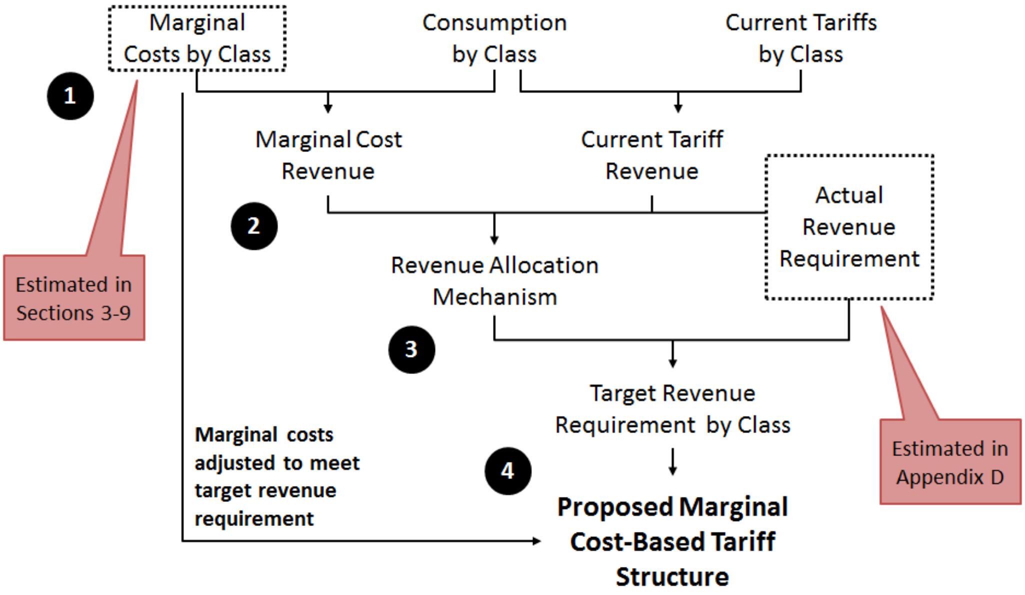
Steps for developing an economically efficient tariff structure based on marginal costs include:

1. **Calculate marginal cost revenue and current tariff revenue**. The most economically efficient tariffs recover full marginal cost revenues from each customer class and have charges set equal to unit marginal costs. By calculating marginal cost revenues for the total system and comparing them to revenues from current tariffs and the total revenue requirement, we determine how much total adjustment to marginal costs will be necessary to produce tariffs that produce the revenue requirement, and how large a change in total revenues is involved. We calculate marginal cost revenue and current tariff revenue using information on consumption by class, current tariffs by class, and marginal costs by class estimated in Sections B.2 through B.7.
2. **Identify revenue allocation mechanism.** Given the total revenue requirement for each scenario developed in Task 1, we selected revenue allocation mechanisms that reflected each class' contribution to marginal cost revenue while keeping in mind the need to control against major shifts in the revenue allocation based on the current tariff levels. We used two revenue allocation mechanisms in our analysis: equal-percentage-of-marginal cost (EPMC) and a modified EPMC that excludes customer-related costs in calculating the class shares of marginal cost. These mechanisms and the rationale for their use are described in further detail in Section B.8.
3. **Allocate revenue to customer classes.** We determine the target revenue requirement for each customer class using the revenue allocation mechanism identified in step 2 and the revenue requirement in each year based on expected costs for each sector component.
4. **Adjust marginal costs to meet class revenue requirement.** Once the revenue requirement for each class is determined, the next step in development of efficient tariffs is using the structure and level of marginal unit costs to set the charges in each class' tariff, while keeping in mind the need to control adverse bill impacts within classes.

Appendix Figure B.2 shows how Steps 1 through 4 are used to propose a marginal cost-based end-user tariff design.

[43] 7A.4 shows results for our estimates of the revenue requirement for 2013-2030.

Appendix Figure B.2: Steps for Proposing a Marginal Cost-Based End-User Tariff Design



The costs developed for this report are expressed in 2013 AMD to simplify comparisons to current tariffs.

B.2 Selection of Costing/Pricing Periods

For purposes of providing summary tables for this report and for use in evaluation of time-differentiated tariffs, we developed a set of costing/pricing periods that are efficient (grouping hours of similar cost), administratively feasible, and likely to be appropriate for a significant number of years. This section describes how we developed the recommended costing/pricing periods and the resulting periods that proved most suitable for Armenia.[44]

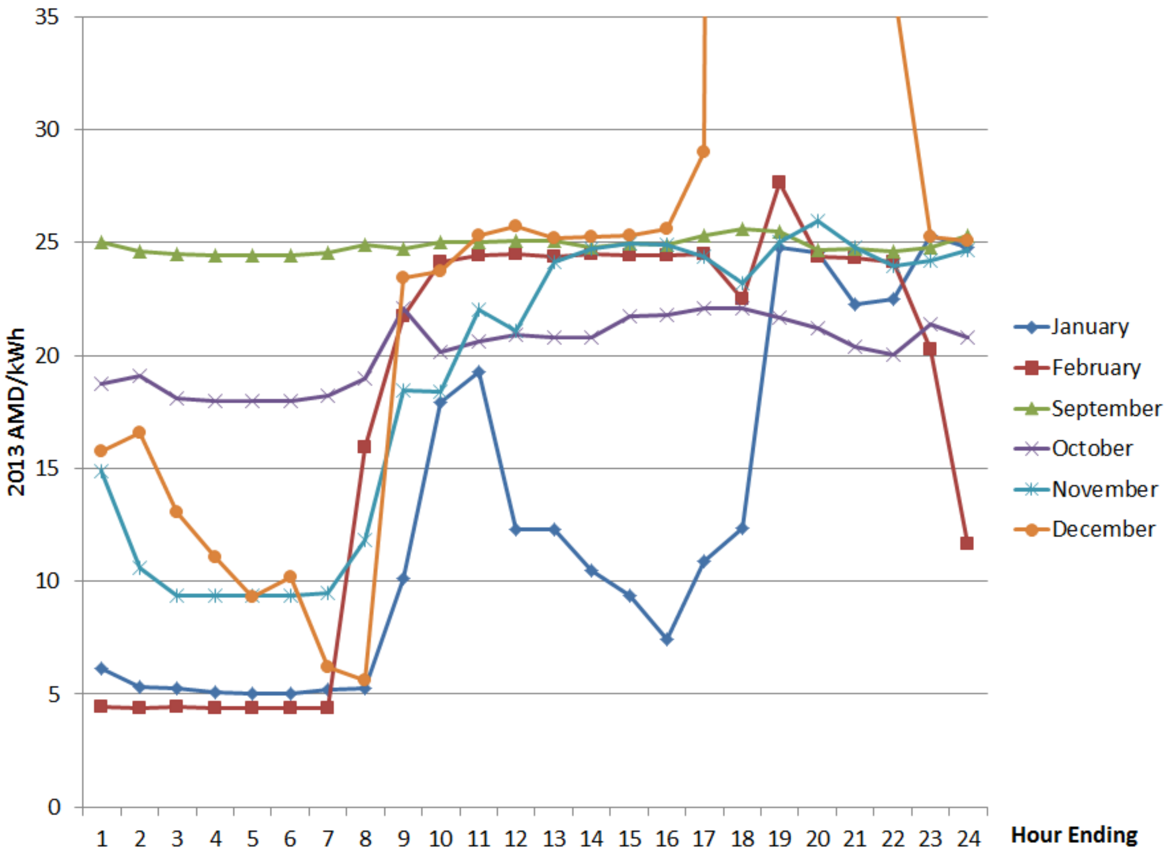
Development of Costing/Pricing Periods

Our process for developing recommended costing/pricing periods is to sum all the time-varying marginal costs for each hour of a typical day in each month (development of which are described in later sections of this report) and analyze plots of the resulting cost patterns across months and hours, while taking into consideration administrative feasibility and the need for the periods to be reasonably easy for customers to remember. These time-varying components of marginal cost consist of generation capacity, energy, transmission, and subtransmission/distribution substation/feeder costs. We used marginal cost estimates for the five-year period 2013-2017 for this purpose.

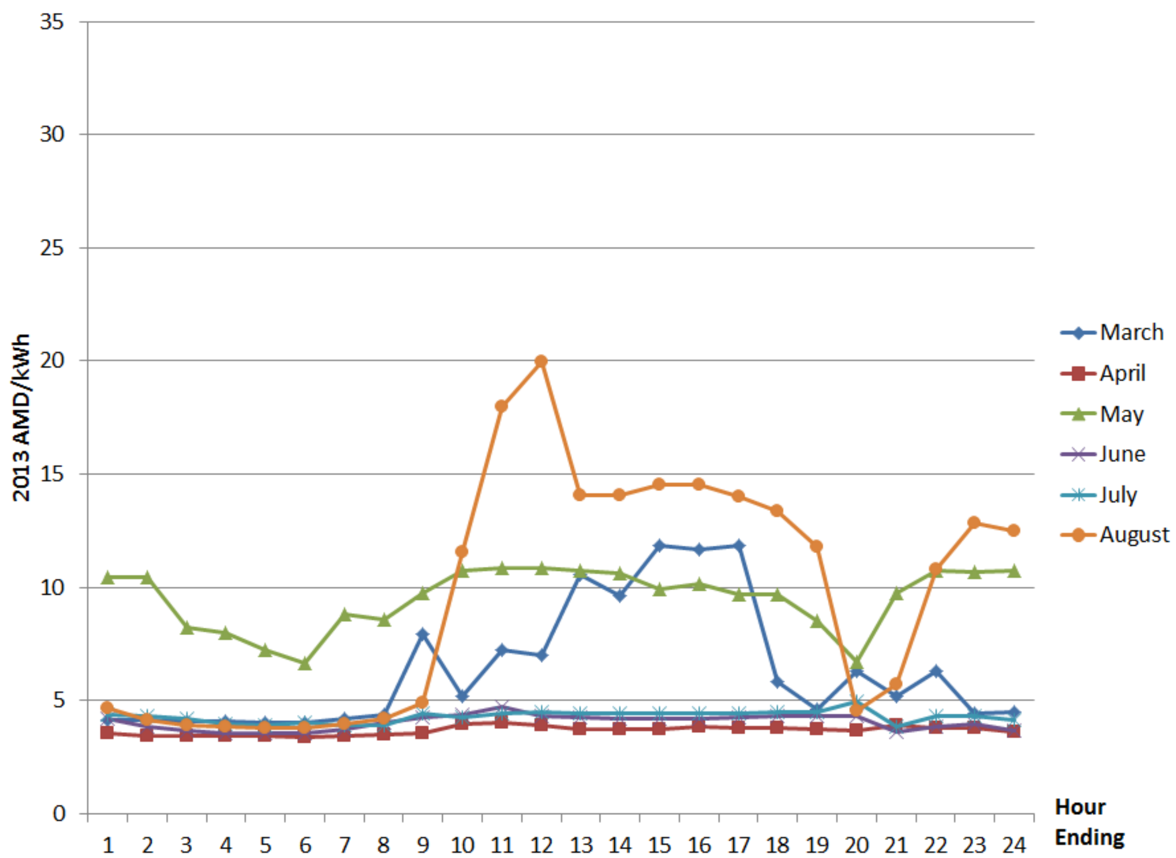
Appendix Figure B.3 and Appendix Figure B.4 are plots of these hourly costs. In these figures December costs are significantly higher than the other months because the historical data available for time-differentiation were very limited. Inclusion of more years of data would likely show more homogeneous cost levels across the typically cold months. September and October generation costs are higher than would be expected based solely on load patterns. During these months, the nuclear plant is scheduled for maintenance and the more expensive Hrazdan TPP runs more frequently to replace this capacity.

[44] We have developed these costing/pricing periods based on the understanding that meters capable of tracking electricity use by period are being phased in for all electricity consumers in Armenia.

Appendix Figure B.3: Typical Day Average Hourly Marginal Costs per kWh 2013-2017 (September – February)



Appendix Figure B.4: Typical Day Average Hourly Marginal Costs per kWh 2013-2017 (March – August)



Results

We limited the number of periods to two seasons and two diurnal periods within each season. We defined the months of September through February as Winter and March through August as Summer. For customer understanding, we used the same peak and off-peak definitions in the Winter and Summer seasons. The periods chosen are:

Winter Peak:	8:01 AM through 12:00 Midnight, September through February
Winter Off-peak:	12:01 AM through 8:00 AM, September through February
Summer Peak:	8:01 AM through 12:00 Midnight, March through August
Summer Off-peak:	12:01 AM through 8:00 AM, March through August

B.3 Generation Marginal Costs

Marginal generation costs include the fixed costs of adding capacity to maintain adequate reliability as load grows, and marginal energy costs incurred when the marginal generating unit produces another kWh in a given hour. In years when there is sufficient capacity to meet reliability targets, a marginal kW does not trigger a capacity addition. Rather, there is a reduction in reliability (an increase in expected outage costs to customers) because load has grown but capacity has not. This "shortage cost" is the short-run marginal generation capacity cost in such a year. In the long-run, the marginal cost of generation capacity is the cost of adding a kW of peaking capacity that restores the system to the optimal reserve margin, and the marginal energy cost is the cost of providing an additional kWh in each hour with that optimal resource mix and amount.

B.3.1 Marginal Energy Costs

Marginal energy costs consist of variable running cost (including variable O&M expense) and the revenue requirement for cash working capital per kWh of the generation resource at the margin. Cash working capital is required to bridge the gap between the time generators are paid for energy and the time the distribution utility is reimbursed by its customers. The marginal energy costs are adjusted for marginal energy losses, which are a function of load flows in a given hour. The development of the loss factors is described in Section B.6.2.

The following subsections describe the steps to develop marginal energy costs and show our marginal energy cost results for the 2013-2021 period.

Development of Marginal Energy Costs

The System Operator in Armenia dispatches available generating units to minimize cost (including wear and tear on units from start-ups and cycling) and provide reliable service.

Using a production cost simulation model, we developed estimates of the variable running cost per kWh of the generation resource at the margin in each hour of the year for the period 2013 – 2021. Key inputs to the simulation model include annual peak load forecast; hourly load shape; and available resources and their variable costs, maintenance schedules and forced outages rates.[45] We then averaged these marginal running costs over the hours in each costing period. The results are shown in Appendix Table B.1.

[45] Information on hourly load, maintenance schedules, and other non-economic dispatch constraints for existing plants were provided by the System Operator. Information on variable costs for existing plants was provided by the PSRC. The annual peak load forecast and information on new plants (variable costs, available capacity, forced outage rate) came from the World Bank's Energy Sector Issues Note.

Appendix Table B.1: Marginal Running Costs by Period (2013 – 2021)[46]

		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD per kWh)		(2013 AMD per kWh)	
		(1)	(2)	(1)	(2)
(1)	2013	15.2001	6.0974	2.5103	0.8425
(2)	2014	15.7439	6.6372	3.0406	0.9119
(3)	2015	16.2444	7.1090	3.5066	1.0306
(4)	2016	18.7407	11.0803	4.1593	1.1497
(5)	2017	15.4491	6.1632	2.6509	0.6214
(6)	2018	15.9786	6.5267	3.2737	0.7087
(7)	2019	16.4152	7.0355	3.7914	0.8168
(8)	2020	18.0831	11.1737	4.3628	0.9073
(9)	2021	1.4987	1.3477	1.3340	1.3327

Appendix Table B.2 shows the derivation of 2013 marginal energy costs in each costing period, when accounting for cash working capital and adjustment for losses.

[46] Marginal running costs and, therefore, marginal costs are significantly lower in 2021 than in previous years because it is assumed that the excess capacity of the new gas plant will fulfill the terms of the gas-electricity swap and therefore incur minimal fuel costs for energy supplied to the domestic population.

Appendix Table B.2: Development of Marginal Energy Costs by Period (2013)

		2013			
		Winter		Summer	
		Peak Hours	Off-Peak Hours	Peak Hour	Off-Peak Hour
		(2013 AMD per kWh)		(2013 AMD per kWh)	
(1)	Marginal Running Cost Including Variable O&M Expense	15.2001	6.0974	2.5103	0.8425
(2)	Variable O&M Expense Included in Marginal Running Costs	0.3450	0.3417	0.2859	0.1610
(3)	Marginal Running Cost less Variable O&M Expense (1)-(2)	14.8551	5.7557	2.2244	0.6815
(4)	A&G Loading for Variable O&M (2) x 0.000%	0.0000	0.0000	0.0000	0.0000
(5)	Cash Working Capital				
	Non-Fuel [(2) + (4)] x 8.333%	0.0288	0.0285	0.0238	0.0134
	Fuel (3) x 8.333%	1.2379	0.4796	0.2781	0.0852
	Fuel Stock (3) x 0.310%	0.0461	0.0178	0.0069	0.0021
		1.3127	0.5260	0.3088	0.1007
(6)	Revenue Requirement for Working Capital (5) x 3.00%	0.0394	0.0158	0.0093	0.0030
(7)	Marginal Energy Cost (1)+(4)+(6)	15.2395	6.1131	2.5195	0.8455
	Marginal Energy Loss Factors For Supply at:				
(8)	Secondary Voltage	1.2829	1.1754	1.2324	1.1520
(9)	Primary Voltage	1.2212	1.1383	1.1824	1.1201
(10)	Subtransmission Voltage	1.1231	1.0783	1.1023	1.0683
	Marginal Energy Costs Including Losses:				
(11)	Secondary Voltage	19.5507	7.1851	3.1049	0.9740
(12)	Primary Voltage	18.6112	6.9586	2.9792	0.9471
(13)	Subtransmission Voltage	17.1149	6.5916	2.7772	0.9032

Results

The marginal energy cost results by costing period for the entire study period (2013-2021) are shown in Appendix Table B.3.

Appendix Table B.3: Marginal Energy Costs by Period (2013 - 2021)

		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD per kWh)		(2013 AMD per kWh)	
		(1)	(2)	(1)	(2)
Secondary					
(1)	2013	19.5507	7.1851	3.1049	0.9740
(2)	2014	20.2748	8.5470	3.7610	1.1279
(3)	2015	20.9194	9.1545	4.3375	1.2747
(4)	2016	24.1343	14.2690	5.1450	1.4219
(5)	2017	19.8946	7.9357	3.2781	0.7681
(6)	2018	20.5765	8.4037	4.0484	0.8762
(7)	2019	21.1389	9.0589	4.6888	1.0098
(8)	2020	23.2871	14.3883	5.3957	1.1218
(9)	2021	1.9277	1.7333	1.6481	1.6464
Primary					
(10)	2013	18.6112	6.9586	2.9792	0.9471
(11)	2014	19.3004	7.5836	3.6087	1.0252
(12)	2015	19.9141	8.1227	4.1618	1.1586
(13)	2016	22.9745	12.6607	4.9365	1.2924
(14)	2017	18.9385	7.0413	3.1452	0.6981
(15)	2018	19.5877	7.4565	3.8844	0.7964
(16)	2019	20.1230	8.0378	4.4989	0.9179
(17)	2020	22.1680	12.7665	5.1771	1.0197
(18)	2021	1.8351	1.5379	1.5813	1.4965
Subtransmission Voltage					
(19)	2013	17.1149	6.5916	2.7772	0.9032
(20)	2014	17.7487	7.4821	3.3641	1.0088
(21)	2015	18.3130	8.0140	3.8797	1.1401
(22)	2016	21.1274	12.4912	4.6019	1.2718
(23)	2017	17.4159	6.9470	2.9321	0.6870
(24)	2018	18.0129	7.3567	3.6211	0.7837
(25)	2019	18.5052	7.9302	4.1939	0.9033
(26)	2020	20.3857	12.5956	4.8262	1.0034
(27)	2021	1.6875	1.5173	1.4741	1.4727

B.3.2 Marginal Generation Capacity Costs

If load grows in hours when capacity is tight, there is a reduction in reliability, which is a marginal shortage cost imposed on consumers. When the shortage cost is sufficiently high, it is cost-effective to add capacity to restore reliability to the acceptable level. In years when an increment of load would not trigger a capacity addition, there is still a marginal capacity cost – the cost to consumers of the reduced reliability that results when load grows but capacity remains the same. In years when reserves are below the target level, the shortage cost is higher than the cost of adding capacity.

The type of capacity added solely to restore reserves to the required level in response to load growth is generally a peaking unit, such as a combustion turbine. Generating units designed to run more often than peakers have higher fixed costs, which are only justified when their variable costs are low enough to warrant their dispatch in many hours (providing fuel savings), not just in peak hours. The fixed costs of baseload or intermediate units are thus incurred for both capacity and energy reasons.

Armenia has sufficient capacity to meet peak demand, but will struggle to meet its reserve margin beginning in 2017. Small additions of renewable generation are planned for 2017.[47] Current discussions suggest that the next major unit, to be added in 2021, will be a 1100 MW nuclear unit. As an alternative, the Government might consider new 800 MW CCGT plant. We analyzed the cost of both options and found that the CCGT option has the lower net cost. As a result, our marginal generation capacity costs are based on this option.[48]

The CCGT would be baseloaded and run more hours than a normal peaker, and would therefore provide fuel savings to the system as it displaced higher-cost units during those extra hours. Therefore, using the CCGT as the basis for marginal generation capacity cost requires crediting the fixed cost of the new unit for fuel savings.

Development of Marginal Generation Costs

The development of marginal generation costs includes the following steps:

- **Estimating the annualized cost of the CCGT unit.** This reflects all fixed costs of the unit including: investment costs annualized using an economic carrying charge, fixed O&M and an allowance for revenue requirement needed to fund working capital. The working capital factor includes cash, materials and spares, and prepayments.[49]
- **Reducing the annualized cost by expected fuel savings.** To yield a pure capacity cost, the annual costs per kW must be reduced by the expected fuel savings provided by a marginal kW of new capacity
- **Adjusting the annualized cost to account for surplus (or deficit) of capacity in the system**. The estimated annualized cost of new capacity per kW reflects the long-run marginal cost of capacity. This cost must be reduced in periods when excess surplus is available (and increased in periods of supply deficit) to account for the sufficient (or insufficient) level of reliability in the system

[47] Based on the Armenia Energy Sector Note (2011), this analysis assumed that two mid-sized hydropower plants—Lori-Berd HPP and Shnokh HPP—will come online in 2017.

[48] Developing marginal costs based on not optimal supply options produces nonsensical results. For this reason, we use the CCGT option to develop estimates of marginal cost. However, we still analyze the impacts of the nuclear option on end-user tariffs in our determination of marginal cost-based tariffs in Section 7B.8.

[49] Each of the major factors used to convert the investment cost of the unit to an annual value is discussed in Sections Appendix A.1- A.3 and Appendix 7B.6.3

- **Time-differentiating annualized cost by the Loss-of-Load Probability (LOLP).** This time differentiation is needed to account for the fact that the need for an additional kW of capacity is more likely to occur in some hours than in others.

Each of these steps is described in further detail prior to the table presenting the interim results for that step. Appendix Table B.4 shows the development of the annualized cost of the CCGT unit.

Appendix Table B.4: Annual Cost of CCGT Unit

		(2013 AMD per kW)
(1)	Installed Cost of Gas-fired CCGT	443,833.83
(2)	Substation	0.00
(3)	Infrastructure Development	0.00
(4)	Total Investment	443,833.83
(5)	With General Property Loading (4) x 1.0000	443,833.83
(6)	Annual Economic Charge Related to Capital Investment	3.26%
(7)	A&G Loading	0.00%
(8)	Total Annual Carrying Charge (6)+(7)	3.26%
(9)	Annualized Costs (4) x (8)	14,482.41
(10)	Fixed O&M Expenses per kW	5,602.43
(11)	With A&G Loading (10) x 1.0000	5,602.43
(12)	Subtotal (9)+(11)	20,084.84
	Working Capital	
(13)	Material and Spares (5) x 3.84%	17,043.22
(14)	Prepayments (5) x 0.94%	4,172.04
(15)	Cash Working Capital Allowance (12) x 8.33%	466.87
(16)	Total Working Capital (13)+(14)+(15)	21,682.13
(17)	Revenue Requirement for Working Capital (16) x 3.00%	650.46
(18)	Annual Fixed Costs (12)+(17)	20,735.30

The annual costs per kW shown in Appendix Table B.4 are adjusted for fuel savings in Appendix Table B.5 by multiplying the unit's expected energy production per kW by the difference between the unit's running cost and the average system marginal running cost in the unit's first full year of operation. This crediting of annual fixed costs of the marginal kW for fuel savings recognizes that the last kW is required to meet marginal load only in a single (or very few) hours of the year. If the unit runs in other hours, that is because it displaces a resource with higher running costs. Using fuel savings in the first full year of operation results in a net annual cost of moving the unit forward in time to meet a marginal increment of load. The last line on Appendix Table B.5 divides the annual cost by one minus the effective forced outage rate (EFOR) of the unit. This adjustment recognizes that the unit will not always be available to provide an additional kW of capacity when needed, and grosses up the investment to represent a “perfect” kW that is available in all hours when it can be economically dispatched.

Appendix Table B.5: Net Annual Marginal Cost of CCGT Capacity

(1)	Gas-Fired CCGT Running Cost (2013 AMD per kWh)	1.34
(2)	Average Marginal Running Cost in Hours When CCGT Runs in 2021 - First full year of operation (2013 AMD per kWh)	1.39
(3)	Savings per kWh Run (2)-(1) (2013 AMD per kWh)	0.06
(4)	2020 Expected Hours of Operation of Gas-Fired CCGT	7,446
(5)	Annual Fuel Savings (2013 AMD per kW) (3)*(4)	418
(6)	Annual Fixed Costs per kW	20,735
(7)	Annual Fixed Costs Net of Fuel Savings (2013 AMD per kW) (6)-(5)	20,317
(8)	Adjustment for Effective Forced Outage Rate (7) / 0.95	21,387

Appendix Table B.5 shows annual marginal generation capacity cost for a year in which an increment of peak load would trigger a capacity addition. This can been considered an estimate of long-run marginal generation capacity cost. In any particular year, marginal load growth will not necessarily trigger a capacity addition. However, it will reduce the reliability of service for customers over all. The short-run marginal cost of generation capacity can be computed for a particular year by adjusting the net annual cost of the next capacity addition by the ratio of expected loss-of-load hours (LOLH) in that year to target LOLH, as shown in Appendix Table B.6. This ratio, which is less than one when there is excess capacity on the system (and more than one when the system has below target reliability), reflects the reduced (or increased) capacity cost in those years.[50] LOLH information for the Armenian system is not available. As a proxy for the ratio of expected to target LOLH in each year, we used the ratio of target to expected system reserve margin. As with the LOLH ratio, a value of 1 means the system has the target level of reliability, while a ratio of less than 1 means there is excess capacity and vice versa.

[50] The rationale for this adjustment is described in more detail in Appendix A.

Appendix Table B.6: Annual Short-Run Marginal Generation Capacity Costs based CCGT Unit, 2013-2021

	Annual Net Cost of Generation Capacity	Forecast Reserve	Target Reserve	Ratio of Target to Forecast Reserve	Short-Run Marginal Generation Capacity Cost
	(2013 AMD per kW)				(2013 AMD per kW)
	(1)	(2)	(3)	(4)	(5)
				(3)/(2)	(1) x (4)
2013	21,387	83%	25%	0.30	6,472
2014	21,387	80%	25%	0.31	6,695
2015	21,387	77%	25%	0.32	6,931
2016	21,387	74%	25%	0.34	7,178
2017	21,387	15%	25%	1.64	34,986
2018	21,387	14%	25%	1.85	39,476
2019	21,387	12%	25%	2.10	44,961
2020	21,387	10%	25%	2.44	52,093
2021	21,387	63%	25%	0.40	8,545

The annual costs must then be time-differentiated. Our production simulation model provides estimates of loads and generation capacity available in each hour. We used the difference between load and generation capacity to approximate hourly relative loss-of-load probability – the relative likelihood that load growth in a particular hour will trigger the need for additional capacity (or, in the event the system has excess capacity create a shortage cost by increasing the likelihood of outage).[51] Appendix Table B.7 shows the resulting generation capacity cost time-differentiation factors, summarized by costing period.

Appendix Table B.7: Time-Differentiation Factors for Generation Capacity Costs

		Estimated Relative Loss-of-Load Probability
	Winter	
(1)	Peak	41.5%
(2)	Off-Peak	16.9%
	Summer	
(3)	Peak	28.5%
(4)	Off-Peak	13.0%
		100.0%

[51] The procedure was to calculate the difference between load and capacity in each hour, taken the inverse of those values, and then compute each hour's inverse as a percent of the sum of all hour's inverses. The data used were for the years 2013-2017.

Results

Appendix Table B.8 shows the monthly marginal generation capacity costs per kW at each voltage level of service, by costing period. The annual costs, adjusted for peak demand losses,[52] are assigned to costing periods using the factors in Appendix Table B.7 and divided by the number of months to produce monthly costs per kW for each year.

Appendix Table B.8: Monthly Generation Capacity Cost per kW by Voltage Level

		2013	2014	2015	2016	2017	2018	2019	2020	2021
		----------------2013 AMD per kW per month------------------								
	Monthly Marginal Generation Capacity Cost									
(1)	Winter Peak	448	464	480	497	2,423	2,734	3,113	3,607	592
(2)	Winter Off-Peak	182	188	195	202	984	1,111	1,265	1,466	240
(3)	Summer Peak	308	318	330	341	1,664	1,878	2,139	2,478	406
(4)	Summer Off-Peak	141	145	151	156	760	857	976	1,131	186
	Adjusted for Losses:									
	Subtransmission Service (35+ KV)									
(5)	Winter Peak	487	504	522	540	2633	2970	3383	3920	643
(6)	Winter Off-Peak	198	205	212	219	1070	1207	1375	1593	261
(7)	Summer Peak	334	346	358	371	1808	2040	2324	2693	442
(8)	Summer Off-Peak	153	158	164	169	826	931	1061	1229	202
	Primary Service									
(9)	Winter Peak	517	535	554	574	2797	3156	3595	4165	683
(10)	Winter Off-Peak	210	218	225	233	1137	1283	1461	1693	278
(11)	Summer Peak	355	368	381	394	1922	2168	2469	2861	469
(12)	Summer Off-Peak	162	168	174	180	877	990	1127	1306	214
	Secondary Service									
(13)	Winter Peak	546	565	585	606	2953	3332	3795	4397	721
(14)	Winter Off-Peak	222	230	238	246	1200	1354	1542	1787	293
(15)	Summer Peak	375	388	402	416	2028	2289	2607	3020	495
(16)	Summer Off-Peak	171	177	183	190	926	1045	1190	1379	226

B.4 Marginal Transmission Costs

The long-term marginal cost of transmission can be estimated from the typical investment per kW of transmission added to meet load growth. Transmission investment is somewhat lumpy, so the addition of capacity in a given year does not necessarily reflect load growth in that year. We rely on the cost of budgeted growth-related transmission projects over the budget period as the basis for our marginal cost estimates.

Projects considered to be growth-related include those driven by load growth and those necessary to upgrade existing facilities to maintain the target level of reliability. The following transmission expenditures are not considered marginal:

- **Replacing existing facilities without adding capacity**. These investments would be undertaken even in the absence of load growth and, therefore, are not marginal
- **Projects that connect generation to the network.** These projects are generation-related and not functionally transmission. These costs are included in marginal generation capacity calculations if they are requirements of the new generation
- **Projects that are designed primarily to facilitate exports.** These projects are also not marginal transmission costs because they would be undertaken even in the absence of marginal domestic load growth.

[52] Determination of demand losses is discussed in Section 7B.6.2.

Development of Marginal Transmission Costs

To estimate marginal transmission investment costs, we reviewed HVEN's investment plan for the period 2012-2016 and estimated the share that is growth-related. Appendix Table B.9 shows the size of these investments, the load growth driving them, and the total investment per kW of load growth.

Appendix Table B.9: Marginal Transmission Investment

(1)	Investment in Growth-Related Transmission, 2012-2016 (Thousands of 2013 AMD)	20,245,052
(2)	Estimated Additions to Transmission Peak Load, 2012-2016 (MW)	102.50
(3)	Marginal Investment in Growth-Related Transmission Substations per kW (2013 AMD) (1) / (2)	197,513

When load growth requires transmission investment, marginal transmission O&M expenses are also incurred. We estimated the per-kW marginal transmission O&M by dividing annual transmission O&M expenses for the years 2009-2011 by system peak load on the transmission system, as shown in Appendix Table B.10, and averaging the results over the three years. These expenses include the cost of materials, repairs, salaries, social payments, and other expenses.[53]

Appendix Table B.10: Marginal Transmission O&M Expense per kW

	Year	Total Transmission Expense	System Peak Loads	Transmission Expense Per kW of Peak Load	Weighted Labor and Materials Cost Index	Transmission Expense Per kW of Peak Load
		(Million AMD)	(kW)	(AMD)	(2013=1.00)	(2013 AMD)
				(1) / (2) x 1,000,000		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	1,783	1,200,580	1,485.05	0.80	1,850.36
(2)	2010	1,784	1,152,500	1,547.73	0.85	1,828.68
(3)	2011	1,784	1,275,510	1,398.47	0.89	1,567.02
(4)	Used in Study (average of 2009-2011)					1,748.68

[53] Expenditure on salaries may include some costs that will be capitalized as investments. However, we lacked information to determine the extent to which salaried HVEN employees work on capital expenditure projects.

Appendix Table B.11 shows the development of annualized marginal transmission cost, which follows the same procedure used for the annual generation capacity cost on Appendix Table B.4 above.

Appendix Table B.11: Annual Marginal Transmission Cost

		(2013 AMD)
(1)	Marginal Investment per kW	197,513
(2)	With General Property Loading (1) x 1.0000	197,513
(3)	Annual Economic Carrying Charge Related to Capital Investment	3.47%
(4)	A&G Loading (plant related)	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	3.47%
(6)	Annualized Costs (2) x (5)	6,852.63
(7)	O&M Expenses per kW of Transmission Peak Demand	1,748.68
(8)	With A&G Loading (7) x 1.0000 (Non-plant Related)	1,748.68
(9)	Subtotal (6) + (8)	8,601.31
	Working Capital	
(10)	Material and Spares (2) x 1.25%	2,468.91
(11)	Prepayments (2) x 0.02%	39.50
(12)	Cash Working Capital Allowance (8) x 8.33%	145.72
(13)	Total Working Capital (10) + (11) + (12)	2,654.13
(14)	Revenue Requirement for Working Capital (13) x 5.38%	142.79
(15)	Total Annual Transmission Costs (9) + (14)	8,744.11

Transmission capacity is sized to handle annual peak demands on the transmission system. We estimated relative probability of annual transmission system peak, based on three years of historical hourly system loads, to time-differentiate transmission marginal costs. Appendix Table B.12 shows the time-differentiation factors, which were also used to time-differentiate distribution substation and feeder costs.

Appendix Table B.12: Time-Differentiation Factors for Marginal Transmission and Distribution Costs

			Estimated Relative Probability of System Peak
	Winter		
(1)		Peak	99.94%
(2)		Off-Peak	0.00%
	Summer		
(3)		Peak	0.03%
(4)		Off-Peak	0.03%
(5)	Total		100%

Results

Appendix Table B.13 shows the monthly time-differentiated marginal transmission costs, using the annual costs developed in Appendix Table B.11 (after adjustment for demand losses) and the time-differentiation factors on Appendix Table B.12. The annual costs have been divided by number of months to convert to monthly costs.

Appendix Table B.13: Monthly Marginal Transmission Costs

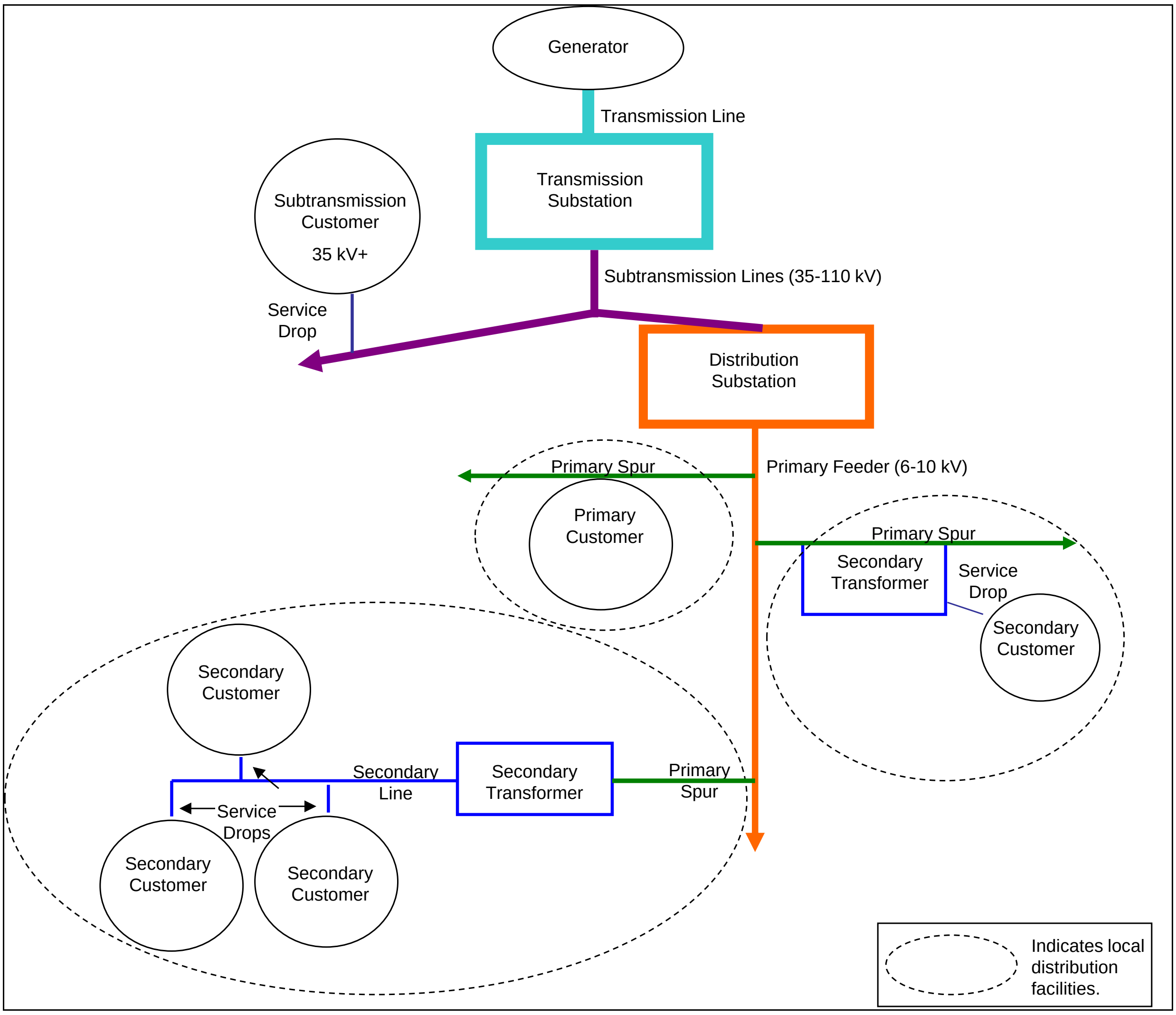
		(2013 AMD per kW-month)
	Monthly Marginal Transmission Cost	
(1)	Winter Peak	1456.50
(2)	Winter Off-Peak	0.00
(3)	Summer Peak	0.40
(4)	Summer Off-Peak	0.45
	Adjusted for Losses	
	Subtransmission Service (35+ KV)	
(5)	Winter Peak	1582.68
(6)	Winter Off-Peak	0.00
(7)	Summer Peak	0.43
(8)	Summer Off-Peak	0.49
	Primary Service	
(9)	Winter Peak	1,681.77
(10)	Winter Off-Peak	0.00
(11)	Summer Peak	0.46
(12)	Summer Off-Peak	0.52
	Secondary Service	
(13)	Winter Peak	1,775.29
(14)	Winter Off-Peak	0.00
(15)	Summer Peak	0.48
(16)	Summer Off-Peak	0.55

B.5 Marginal Distribution Costs

Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Marginal cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components. In fact, for most distribution systems, this two-part segmentation of distribution equipment is not consistent with the cost drivers.

The simplified diagram below illustrates the basic structure of Armenia's electric system and the various configurations of typical customer connections.

Appendix Figure B.5: Simplified Diagram of Armenian Electric System



We refer to service drops, secondary lines, secondary transformers and the small amount of primary line (the primary "spur") that links the transformer to the main primary line as local distribution facilities (shown in dashed ovals in the figure). These components are designed using engineering design standards that take into consideration the number of customers and the *maximum expected* loads of customers who will eventually use those facilities, over the life of the facilities. The cost per kVA of local distribution facilities can vary with type of service (overhead or underground), customer density, and customer size (due to economies of scale). The distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected long-term peak load of customer.

Because the marginal cost of local distribution facilities is incurred based on the maximum expected load of customers, and does not vary with a customer's actual peak load from month to month, or (barring major expansion) from year to year, it is efficient to recover these marginal distribution costs in a fixed monthly charge imposed on the customer's maximum expected load (or a proxy such as transformer size, contract capacity, or actual peak in the past year or two).

ENA generally adds subtransmission lines, distribution substation capacity and primary feeders as peak load in the areas served by these facilities grows. Thus, these costs are appropriately recovered in time-differentiated monthly usage charges assessed on peak demands within the period or per-period energy use.

Using available information, we computed three components of distribution costs – typical meter costs per customer by class, typical local facilities cost per customer by class (including service drop, secondary lines, line transformers and primary spurs);[54] and time-differentiated subtransmission line, substation and feeder costs, varying by voltage level of service. Customer-related service expenses such as customer information, meter reading, bill handling, etc. are included in the distribution O&M expense estimates, but not separately identified.

B.5.1 Marginal Distribution Investment

The following subsections describe how we estimate investment costs for the three components of distribution costs described above.

Meter Investment

From the PSRC we obtained estimates of the installed cost of a typical electronic meter currently being installed for each class. These meter costs are shown on Appendix Table B.14.

Appendix Table B.14: Typical Meter Investment per Customer by Class

	Customer Class	Meter Investment (2013 AMD per Customer)
(1)	35 kV and above	77,865.58
(2)	6(10) kV	77,865.58
(3)	0.4 kV	15,573.12
(4)	Residential	15,573.12

Local Facilities Distribution Investment

From information on connection costs, we estimated the installed cost per customer of a typical investment in service drop, and secondary and primary facilities for each customer class, net of customer contributions required by the company's connection policy. The installed costs by class are shown in Appendix Table B.15.

[54] Information on design demands of customers was not available so we estimated an average level of design demand for each class and computed local facilities costs on a per-customer basis, by class. These costs were added to the per-customer meter marginal costs.

Appendix Table B.15: Customer-Related Distribution Investment per Customer by Class

	Customer Class	Average Investment per Customer (2013 AMD)
(1)	35 kV and above	68,750,000
(2)	6(10) kV	11,458,333
(3)	0.4 kV	687,500
(4)	Residential	229,167

Subtransmission Lines, Distribution Substations and Feeders

As outlined above, subtransmission, distribution substation and feeder capacity is added based upon year-to-year changes in local peak loads, not based on design demands. Therefore, the marginal costs of these investments are most appropriately expressed in terms of kilowatts of load growth, and time-differentiated to indicate in which periods load growth is most likely to trigger capacity additions.

ENA's marginal (growth-related) investment in these components was estimated by taking the total capital budget for the period 2012-2016 less the portion attributable to connections and meters, and multiplying the result by 10 percent. This 10 percent adjustment reflects the fact that much of the distribution budget is for replacements that would be made even in the absence of load growth, and is therefore not marginal. The growth-related budget was divided by the estimated distribution peak load growth for the same years.[55] This gives an estimate of the typical investment per kilowatt of load growth at the substation level. The calculations are shown in Appendix Table B.16.

Appendix Table B.16: Marginal Distribution Investments in Subtransmission Lines, Substation and Feeder Investment

(1)	Investment in Growth-Related Additions to Distribution Plant Other Than Local Facilities and Meters, 2012-2016 (Thousands of 2013 AMD)	1,977,038
(2)	Estimated Additions to Distribution Pead Load, 2012-2016 (MW)	95.00
(3)	Marginal Investment in Growth-Related Distribution per Kilowatt (2013 AMD) (1) / (2)	20,810.92

[55] Ideally the denominator for this calculation should be growth in the sum of individual substation non-coincident peak (NCP) loads because substation and feeder investment is driven by local, not system-wide coincident peaks. However, information on NCPs was not available. We used system peak less an estimate of peak demands by subtransmission customers, which do not use distribution substations or primary feeders. They may use a portion of subtransmission lines, but ENA budget information was not detailed enough for us to segregate subtransmission investment.

B.5.2 Distribution Operation and Maintenance Expenses

Each type of distribution component requires O&M, so marginal O&M expenses are incurred when load growth triggers capacity additions. We began with an analysis of ENA's distribution O&M expenses in the period 2009-2011 as a guide for estimating marginal O&M costs.

Distribution O&M used in our analysis includes the categories of "operating expenses" and "bad debt."[56] We apportioned operating expenses into two categories: meters/local facilities, and subtransmission/substations/feeders based on the shares of these two categories in ENA's investment plans for 2007-2011. This procedure assumes that O&M expense is proportional to investment cost and that recent capacity additions are representative of total capacity requiring O&M. Bad debt was added to the meters/local facilities expense category because it is related to number of customers. We refer to the sum as customer-related expenses.

O&M expenses by category for each year were converted into 2013 dollars using a weighted labor and material cost index. The subtransmission/substation/feeder expenses were then divided by kilowatts of peak load. The customer-related expenses were divided by weighted number of customers (with the weights based on the relative size of the per-customer typical meter/local facilities investment for each class). For each category of O&M we used an average of the three years values to represent future marginal expenses.

Appendix Table B.17 shows the development of the customer-related O&M expense per weighted customer. Appendix Table B.18 takes that value and multiplies by the appropriate weight for each class to yield a customer-related O&M expense per customer.

Appendix Table B.17: Customer-Related O&M per Weighted Customer

		2009	2010	2011
(1)	Customer-Related Expenses (Thousand AMD)	6,469,825	5,664,257	10,504,008
(2)	Customers	1,027,822	1,044,803	1,088,386
(3)	Weighted Number of Customers (2) x 1.389	1,427,391	1,450,973	1,511,499
(4)	Expense Per Weighted Customer (AMD) [(1) / (3)] x 1000	4,533	3,904	6,949
(5)	Labor Cost Index (2013 = 1.00)	0.86	0.97	0.94
(6)	Expense Per Weighted Customer in 2013 AMD (4) / (5)	5,263	4,023	7,421
(7)	Estimated Annual Expense Per Weighted Customer (2013 AMD) (Average of 2009-2011)	---------------------	5,569	----------------------

[56] Further detail on the breakdown of distribution O&M expenses was not available.

Appendix Table B.18: Customer-Related O&M per Customer

	Class	Weighting Factor	Annual Customer-Related O&M Expense Per Customer
			(2013 AMD)
			(1) x 5569.07
		(1)	(2)
(1)	35 kV and above	281.23	1,566,184
(2)	6(10) kV direct	47.14	262,507
(3)	0.4 kV	2.87	15,998
(4)	Residential	1.00	5,569

Appendix Table B.19 shows the development of the subtransmission/substation/feeder O&M.

Appendix Table B.19: Subtransmission/Substation/Feeder O&M per kW of Peak Demand

	Year	Total Distribution Substation Expenses	Estimated Distribution Substation Coincident Peak Loads	Substation Expenses Per kW of Substation Coincident Peak Loads	Weighted Labor and Materials Cost Index	Substation Expenses Per kW of Substation Coincident Peak Loads
		(Million AMD)	(kW)	(AMD)	(2013=1.00)	(2013 AMD)
				(1) / (2) x 1,000,000		(3) / (4)
		(1)	(2)	(3)	(4)	(5)
(1)	2009	19,854	1,121,680	17,700.57	0.81	21,761.45
(2)	2010	23,269	1,065,500	21,838.89	0.87	25,124.47
(3)	2011	17,035	1,180,710	14,427.73	0.90	16,021.02
(4)	Used in Study (average of 2009-2011)					20,968.98

B.5.3 Annual Distribution Marginal Costs

Appendix Table B.20 and Appendix Table B.21 show the derivation of annualized customer-related distribution costs and subtransmission/substations/feeder costs, respectively.

Appendix Table B.20: Annualized Marginal Customer-Related Distribution Costs

		35 kV and above	6(10) kV	0.4 kV	Residential
		--------- (2013 AMD per Customer) --------			
Customer-related Investments		(1)	(2)	(3)	(4)
(1)	Meter Investment per Customer	77,866	77,866	15,573	15,573
(2)	With General Property Loading (1) x 1.0000	77,866	77,866	15,573	15,573
(3)	Annual Economic Charge Related to Capital Investment	10.67%	10.67%	10.67%	10.67%
(4)	Local Facilities Investment per Customer	68,750,000	11,458,333	687,500	229,167
(5)	With General Property Loading (1) x 1.0000	68,750,000	11,458,333	687,500	229,167
(6)	Annual Economic Charge Related to Capital Investment	9.35%	9.35%	9.35%	9.35%
(7)	A&G Loading (Plant Related)	0.00%	0.00%	0.00%	0.00%
(8)	Total Carrying Charge Meters (3) + (10)	10.67%	10.67%	10.67%	10.67%
(9)	Total Carrying Charge Local Facilities (9) + (10)	9.35%	9.35%	9.35%	9.35%
(10)	Annualized Meter Costs (2) x (8)	8,311	8,311	1,662	1,662
(11)	Annualized Local Facilities Costs (5) x (9)	6,425,100	1,070,850	64,251	21,417
(12)	Annualized Meter, Local Facilities & Service Costs (14)+(15)+(16)	6,433,410	1,079,161	65,913	23,079
Customer-related O&M					
(13)	Customer-Related O&M Expenses	1,566,184	262,507	15,998	5,569
(14)	With A&G Loading [(13)+(14)] x 1.0000 (Non-plant Related)	1,566,184	262,507	15,998	5,569
(15)	Customer-Related Costs (12) + (14)	7,999,594	1,341,668	81,912	28,648
	Working Capital				
(16)	Materials and Spares [(2) + (5)] x 4.87%	3,351,917	561,813	34,240	11,919
(17)	Prepayments [(2) + (5)] x 0.080%	55,062	9,229	562	196
(18)	Cash Working Capital (14) x 8.33%	130,515	21,876	1,333	464
(19)	Revenue Requirement for Working Capital [(16)+(17)+(18)] x 12.83%	453,861	76,071	4,636	1,614
(20)	Total Annual Marginal Customer-Related Costs (15) + (19)	8,453,455	1,417,739	86,548	30,262

Appendix Table B.21: Annualized Subtransmission/Substation/Feeder Costs

		(2013 AMD per kW)
(1)	Marginal Investment per kW	20810.92
(2)	With General Property Loading (1) x 1.0000	20810.92
(3)	Annual Economic Carrying Charge Related to Capital Investment	9.35%
(4)	A&G Loading (plant related)	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	9.35%
(6)	Annualized Costs (2) x (5)	1944.91
(7)	O&M Expenses	20968.98
(8)	With A&G Loading (7) x 1.0000 (Non-plant Related)	20968.98
(9)	Subtotal (6) + (8)	22913.89
	Working Capital	
(10)	Material and Spares (2) x 4.87%	1013.49
(11)	Prepayments (2) x 0.08%	16.65
(12)	Cash Working Capital Allowance (8) x 8.33%	1747.42
(13)	Total Working Capital (10) + (11) + (12)	2777.56
(14)	Revenue Requirement for Working Capital (13) x 12.83%	356.36
(15)	Total Subtransmission/ Substation/Feeder Costs (9) + (14)	23270.25

B.5.4 Time-Differentiation of Marginal Distribution Costs

Investment in subtransmission/substations/feeders depends upon growth in peak loads in the particular areas served by these facilities. Ideally we would assign annual costs to costing periods based on a statistical analysis of the patterns of hourly loads on substations. However, because that hourly information was not available, we used the same relative probability of peak estimates applied to transmission costs to time-differentiate subtransmission/substation/feeder cost. Appendix Table B.22 applies demand losses, time-differentiates these costs, and converts them to monthly costs per kW.

Appendix Table B.22: Monthly Subtransmission/Substation/Feeder Marginal Costs by Period

(2013 AMD per kW-month)

	Monthly Marginal Subtransmission/Substation/Feeder Cost	
(1)	Winter Peak	3,876.12
(2)	Winter Off-Peak	0.00
(3)	Summer Peak	1.05
(4)	Summer Off-Peak	1.20
	Adjusted for Losses	
	Subtransmission Service (35+ KV)	
(5)	Winter Peak	0.00
(6)	Winter Off-Peak	0.00
(7)	Summer Peak	0.00
(8)	Summer Off-Peak	0.00
	Primary Service	
(9)	Winter Peak	4,326.15
(10)	Winter Off-Peak	0.00
(11)	Summer Peak	1.18
(12)	Summer Off-Peak	1.34
	Secondary Service	
(13)	Winter Peak	4,566.74
(14)	Winter Off-Peak	0.00
(15)	Summer Peak	1.24
(16)	Summer Off-Peak	1.41

B.6 Key Factors in Marginal Cost Analysis

The following subsections describe how we estimate three factors—working capital, losses, and economic carrying charges—that are used throughout our analysis of marginal generation, transmission and distribution costs.

B.6.1 Working Capital

Working capital consists of cash and materials and spares held in inventory, as well as prepayments. The cash component is a function of the difference in timing of the utility's payments to its suppliers, and its customers' payments of their bills. We assumed that the utilities in Armenia require cash working capital equal to one month's O&M, or 8.5 percent of O&M expense. We estimated the materials and spares element of working capital from the ratio of materials and spares to the asset value of existing companies in recent years, and prepayments from the ratio of prepayments to the asset value of existing companies in recent years.

B.6.2 Marginal Losses

Marginal demand loss factors related to the expansion of the physical system are based on total losses at system peak. Total losses include both fixed losses associated predominantly with transformer cores, and variable losses associated with conductors.

To supply an added kW at a customer meter, each component above that meter must accommodate that kW plus all the added losses that will occur from that meter, up to and including that component.[57] The demand loss factors used in this study were developed from estimates of total transmission and total distribution losses recoverable in tariffs. Using information from other utilities, we estimated a further breakdown of distribution losses and the percentage of losses at each level that is fixed.

Marginal energy losses are incurred by moving an additional kWh through the fixed system in a particular hour. Fixed losses are, by definition, not affected by marginal increments in load. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated marginal energy losses by period using a formula that reflects this quadratic dependence and is a function of variable losses at system peak, load at system peak, and hourly loads.

B.6.3 Economic Carrying Charges

To be useful in ratemaking and other marginal cost applications, the marginal investment in new assets must be converted into annual costs using an economic carrying charge. These annual charges reflect the ownership costs of incremental assets: return to stockholders and bondholders, depreciation, corporate income taxes and property taxes.

For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. It is helpful to think of this stream as a series of rental charges that an entrepreneur in a competitive industry would charge for the use of utility equipment. The rental charges would rise as inflation made the equipment more valuable, but tend to decline as technological improvements made newer equipment more attractive to renters. The present value of the entire stream would have to be sufficient to cover the entrepreneur's ownership costs, or the investment would never take place. On the other hand, competition would keep the entrepreneur from charging more than the cost of ownership (including a fair return on the investment). In such a stream of rental charges, the first year's charge represents the cost in today's dollars of making the plant or equipment available for a year. These first-year charges are shown on Appendix Table B.23.

Appendix Table B.23: Economic Carrying Charges

		CCGT	Transmission	Distribution	Meters
		(1)	(3)	(4)	(5)
(1)	Present Value of Revenue Requirements Related to Incremental 1,000 AMD Investment	1,200.51	1,249.38	1,228.49	1,101.36
(2)	First-Year Annual Economic Charge Related to Incremental 1,000 AMD Investment	32.63	34.69	93.46	106.73
(3)	First-Year Annual Economic Charge Related to Incremental Investment [(2)/1,000]	3.26%	3.47%	9.35%	10.67%

[57] The marginal demand loss factor for an individual component is the ratio of the input to the output from that component at time of peak. The capacity adjustment for a component up-stream of a customer meter is the product of all the loss factors including that of component itself.

One major element of the ownership cost of utility equipment is the cost of capital. The utilities in Armenia finance investment with equity (including retained earnings), commercial debt, and concessional loans (which have lower than market interest rates and lags in payment of interest and principle.) No specific information was available on the structure or costs that will be used to finance marginal investment in the Armenian electricity sector. Consequently, we used assumptions in the report "Armenia Energy Sector Note,"[58] the terms of HVEN's current World Bank loan, and ENA's current capital structure and average cost of debt.

An integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. While it is never easy to peg an exact rate of long-term future inflation or technical progress, we have used a rate of 3.96 percent, which is IMF's World Economic Outlook inflation rate forecast for Armenia through 2016.

Another component of the economic carrying charge is an adjustment for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. Because of lack of information on the patterns of replacement, we were unable to include this relatively small element in the economic carrying charges.

Appendix Table B.24 summarizes the key assumptions in the carrying charge calculations.

Appendix Table B.24: Key Assumptions for Economic Carrying Charges

(1)	Type of Plant	CCGT	Nuclear	Transmission	Distribution	Meters	
(2)	Book Life	30	50	40	30	15	Years
(3)	Iowa Curve	Not applicable					
(4)	Tax Life (assumed to be same as book life)	30	50	40	30	15	Years
(5)	Corporate Tax Rate	20.00	20.00	20.00	20.00	20.00	Percent
(6)	Property Tax	0.60	0.60	0.60	0.60	0.60	Percent
(7)	Tax Basis	100.00	100.00	96.15	100.00	100.00	Percent (Proportion of investment that is tax depreciable)
(8)	Investment Tax Credit (if any)	0.00	0.00	0.00	0.00	0.00	Percent
(9)	Inflation	3.96	3.96	3.96	3.96	3.96	Percent (Expected long-term inflation .)
	Composite Incremental Cost of Capital (long-term expected)						
		Share (%)					
(10)	Debt	70	70	75	65	65	Percent
(11)	Preferred Stock						Percent
(12)	Common Equity	30	30	25	35	35	Percent
		Cost (%)					
(13)	Debt	10.69	10.69	3.00	7.63	7.63	Percent
(14)	Preferred Stock						Percent
(15)	Common Equity	18.00	18.00	10.00	18.00	18.00	Percent
(16)	Debt Component	7.48	7.48	2.25	4.96	4.96	Percent
(17)	Preferred Component	0.00	0.00	0.00	0.00	0.00	Percent
(18)	Common Equity Component	5.40	5.40	2.50	6.30	6.30	Percent
(19)	Total Weighted Cost of Capital	12.88	12.88	4.75	11.26	11.26	Percent
(20)	Discount Rate (After-tax Cost of Capital)	11.39	11.39	4.30	10.27	10.27	Percent

[58] "Republic of Armenia, Energy Sector Note: Charged Decisions: Difficult Choices in Armenia's Energy Sector", World Bank, October 2011.

B.7 Marginal Cost Summary Schedules

This section summarizes the marginal energy, generation capacity, transmission, distribution and customer-related costs differentiated by costing period as follows:

- Appendix Table B.25 summarizes the time-differentiated marginal energy costs per kWh and marginal generation, transmission and distribution capacity costs per kW for the year 2013. The generation capacity and energy components are different (in real terms) in other years, and the corresponding summary sheets for 2014-2021 are shown in Section 0.[59]
- Appendix Table B.26 converts the capacity costs to a cost per kWh by period for 2013. This is used as an alternative to recovering generation, transmission and distribution substation capacity costs on the basis of a customer's monthly peak demand. Corresponding tables for 2014-2021 are located in Section B.10.
- Appendix Table B.27 summarizes the monthly customer-related and distribution local facilities costs by class.

[59] Note that costs stated on a per-kW basis are not necessarily what a utility would use to set demand charges. These marginal demand-related costs are simply the sum of the hourly costs. Thus the utility's costs would increase by this amount only if the customer increased load by one kilowatt in every hour of the period. If a customer's increase in load at the time of his seasonal peak were not matched by the same increase in all other hours of the period, an efficient demand charge would be a weighted sum of the hourly costs, not the sum of those costs. The appropriate weights would be each hour's load change relative to the customer's load change in the seasonal peak hour.

Appendix Table B.25: Summary 2013 Time-Differentiated Marginal Costs per kW and per kWh

		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD)			
		(1)	(2)	(3)	(4)
	35 kV and above				
(1)	Energy (per kWh)	17.11	6.59	2.78	0.90
(2)	Generation Capacity (per peak period kW-mo.)	486.95	197.88	334.50	152.70
(3)	Transmission (per peak period kW-mo.)	1,582.68	0.00	0.43	0.49
(4)	Distribution Substation (per peak period kW-mo.)	-	-	-	-
	Total per kW	2,069.64	197.88	334.93	153.19
	6(10) kV direct				
(5)	Energy (per kWh)	18.61	6.96	2.98	0.95
(6)	Generation Capacity (per peak period kW-mo.)	517.44	210.27	355.44	162.26
(7)	Transmission (per peak period kW-mo.)	1,681.77	0.00	0.46	0.52
(8)	Distribution Substation (per peak period kW-mo.)	4,326.15	0.00	1.18	1.34
	Total per kW	6,525.35	210.27	357.07	164.12
	0.4 kV				
(9)	Energy (per kWh)	19.55	7.19	3.10	0.97
(10)	Generation Capacity (per peak period kW-mo.)	546.21	221.96	375.21	171.29
(11)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55
(12)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41
	Total per kW	6,888.24	221.96	376.93	173.25
	Residential				
(13)	Energy (per kWh)	19.55	7.19	3.10	0.97
(14)	Generation Capacity (per peak period kW-mo.)	546.21	221.96	375.21	171.29
(15)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55
(16)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41
	Total per kW	6,888.24	221.96	376.93	173.25

Appendix Table B.26: Summary of 2013 Time-Differentiated Marginal Costs per kWh

		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak
		----------------- (2013 AMD per kWh) -----------------			
		(1)	(2)	(3)	(4)
	35 kV and above				
(1)	Energy	17.11	6.59	2.78	0.90
(2)	Generation Capacity	1.00	0.81	0.69	0.63
(3)	Transmission	3.25	0.00	0.00	0.00
(4)	Distribution Substation	-	-	-	-
	Total	21.37	7.40	3.47	1.53
	6(10) kV direct				
(5)	Energy	18.61	6.96	2.98	0.95
(6)	Generation Capacity	1.06	0.86	0.73	0.67
(7)	Transmission	3.46	0.00	0.00	0.00
(8)	Distribution Substation	8.89	0.00	0.00	0.01
	Total	32.02	7.82	3.71	1.62
	0.4 kV				
(9)	Energy	19.55	7.19	3.10	0.97
(10)	Generation Capacity	1.12	0.91	0.77	0.70
(11)	Transmission	3.65	0.00	0.00	0.00
(12)	Distribution Substation	9.38	0.00	0.00	0.01
	Total	33.70	8.10	3.88	1.69
	Residential				
(13)	Energy	19.55	7.19	3.10	0.97
(14)	Generation Capacity	1.12	0.91	0.77	0.70
(15)	Transmission	3.65	0.00	0.00	0.00
(16)	Distribution Substation	9.38	0.00	0.00	0.01
	Total	33.70	8.10	3.88	1.69

Appendix Table B.27: Summary of Monthly Marginal Customer-Related Costs

	Customer Class	Monthly Marginal Customer Cost per Customer
(1)	35 kV and above	704,455
(2)	6(10) kV	118,145
(3)	0.4 kV	7,212
(4)	Residential	2,522

B.8 Marginal Cost Implications for End-User Tariff Design

For the purpose of this assignment we developed sample end-user tariffs for the years 2013, 2018 and 2021. For 2021 we developed tariffs for each of the eight investment scenarios described in Appendix A.

B.8.1 Class Revenue Allocation and Marginal Cost-Based Structure for 2013

The first step in end-user tariff design is to determine how the total revenue requirement is to be allocated to the various customer classes. If price elasticity of demand is similar across customer classes (or elasticity information is not available), an efficient way to allocate the revenue requirement is to use the equal-percentage-of-marginal-cost (EPMC) approach, which assigns each class a percentage of the revenue requirement equal to its share of total marginal cost revenues. Marginal cost revenues are computed by multiplying the unit marginal costs per kW, per kWh or per customer by corresponding units for each class. For each scenario we used marginal cost revenues computed using the marginal costs per kWh and per customer for that year.[60] Note that the marginal costs used in all 2021 scenarios are based on the more cost-effective CCGT addition and do not reflect a recalculation of the marginal generation costs that would occur if the nuclear unit were added instead.

Appendix Table B.28 compares revenues from current tariffs to marginal cost revenues, and to marginal cost revenues that have been adjusted by an equal percentage to sum the estimated 2013 total revenue requirement,[61] by class. The total marginal cost revenues are below the current tariff revenues, however, this is not the case for all customer classes. Currently, both groups of domestic customers pay below marginal cost while the non-domestic classes paying more than marginal cost.

The revenue requirement for 2013 is below the revenue from current tariffs, but slightly above marginal cost revenues. Efficiently setting class revenue requirements for each class at marginal cost (using EPMC) would result in an average tariff increase of 14% for domestic customers and significant reductions for non-domestic customers.

Appendix Table B.28: Comparison of Current, Marginal Cost and EPMC Revenues by Class (2013)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	46,260,539,473	19,839,415,906	66,099,955,380	34,778,709,244	20,189,685,118	10,157,101,416	131,225,451,157
Class Revenue Requirement Using EPMC	47,843,913,211	20,518,465,707	68,362,378,918	35,969,090,841	20,880,723,691	10,504,751,656	135,716,945,106
Ratio of Proposed Revenue to MC Revenue			1.03	1.03	1.03	1.03	
Percent Change from Revenue at Current Tariffs			14%	-21%	-14%	-28%	

[60] An alternative is to use an average of several years' marginal costs. This approach is particularly useful if the tariffs are to be in place for several years.

[61] The 2013 revenue requirement was determined in Task 1 of this project.

Appendix Table B.29 compares the tariff structure and charge levels in current end-user tariffs in Armenia with the corresponding unit marginal costs. There are a number of important differences including:

- Although winter marginal costs are significantly higher than summer marginal costs, the current tariffs do not have a seasonal component.
- Customers on the current night tariff benefit from low energy charges in off-peak hours, but pay the same price in daytime hours as customers not on the time-of-day (TOD) rate.
- Winter peak marginal costs are similar to the current day charge per kWh, while the summer and winter off-peak marginal costs are significantly lower than current charges.
- The differentials between charges across voltage levels of service in the current tariffs are quite different from the cost-based differentials inherent in the marginal costs by voltage level.
- All tariff revenue is recovered in charges per kWh, although there are significant customer-related (and design-demand-related)[62] costs of service.
- The current tariff does not have a component billed on the basis of monthly peak demand. We would recommend analysis of the appropriateness of time-differentiated demand charges for the two larger customer classes once there is sufficient data available to accurately predict the billing determinants for such charges.

Appendix Table B.29: Comparison of Current Charges and 2013 Unit Marginal Costs by Class

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD			
	Current Tariff Charges					
	Energy Charges (AMD/kWh)					
(1)	Winter day	30.00	30.00	30.00	25.00	21.00
(2)	Winter night	30.00	20.00	20.00	17.00	17.00
(3)	Summer day	30.00	30.00	30.00	25.00	21.00
(4)	Summer night	30.00	20.00	20.00	17.00	17.00
	Marginal Unit Costs					
(5)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(6)	Winter peak	33.70	33.70	33.70	32.02	21.37
(7)	Winter off-peak	8.10	8.10	8.10	7.82	7.40
(8)	Summer peak	3.88	3.88	3.88	3.71	3.47
(9)	Summer off-peak	1.69	1.69	1.69	1.62	1.53

[62] The marginal customer costs developed in this study combine costs per customer and design-demand-related distribution costs because of insufficient information.

The next step is to use the marginal cost information to design a set of tariff charges for each class that preserve as much as possible the efficient price signals, while still producing the allocated class revenues. Because the allocated revenues are close to the marginal cost revenues of each class, we were able to set the per-kWh charges at the relevant marginal cost level, and make slight increases to the monthly customer charges of each class. The per-kWh charges for domestic customers not on the TOD tariff are the weighted averages of the peak and off-peak marginal costs, using this group's consumption in each period as the weights. Appendix Table B.30 shows the results of this exercise.

Appendix Table B.30: 2013 Tariff Design Based on Marginal Costs

	Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
	non-TOD	TOD	TOD	TOD	TOD
Marginal Unit Costs					
Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
Combined Marginal Energy and Capacity Costs (AMD/kWh)					
Winter peak	33.70	33.70	33.70	32.02	21.37
Winter off-peak	8.10	8.10	8.10	7.82	7.40
Summer peak	3.88	3.88	3.88	3.71	3.47
Summer off-peak	1.69	1.69	1.69	1.62	1.53
Proposed Charges					
Monthly Fixed Cost (AMD/customer/month)	2,712	2,712	8,192	135,208	793,322
Energy Charges (AMD/kWh)					
Winter peak		33.70	33.70	32.02	21.37
Winter off-peak		8.10	8.10	7.82	7.40
Winter weighted average	29.86				
Summer peak		3.88	3.88	3.71	3.47
Summer off-peak		1.69	1.69	1.62	1.53
Summer weighted average	3.55				

B.8.2 Class Revenue Allocation and Marginal Cost-Based Tariff Structure for 2018

As shown in Appendix Table B.31, the total revenue requirement in 2018 is higher than in 2013, but the marginal cost revenues have increased even more. Applying a straight EPMC approach to set class revenue requirements in this situation would require a 25% increase in the average domestic tariff. But using a modified EPMC approach – leaving out customer-related marginal costs in the calculation of marginal cost revenues – the domestic share of the revenue requirement is reduced. This result occurs because customer-related costs are a higher share of marginal costs for the domestic class than for non-domestic customers. This modified EPMC approach is an efficient solution to the problem because customers are least price-sensitive to the fixed components of their bills. This means that accurate signaling of marginal customer costs is much less important for efficient allocation of resources than the price signals for electricity consumption. This approach leaves the domestic class with a change in average tariff of 9%, with the non-domestic class increases ranging from 5 to 16%.

Appendix Table B.31: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2018)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	56,437,371,496	25,098,303,424	81,535,674,921	46,540,873,976	27,824,470,320	14,689,628,117	170,590,647,334
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	43,737,333,155	21,317,872,001	65,055,205,156	47,770,145,748	28,365,800,700	14,890,560,924	156,081,712,529
Ratio of Proposed Revenue to Total Class MC Revenue			80%	103%	102%	101%	
Percent Change from Revenue at Current Tariffs			9%	5%	16%	2%	

Appendix Table B.32 shows the efficient tariff design that produces class revenue requirements for 2018. As in Appendix Table B.30, monthly fixed charges were adjusted to account for the differences in the marginal cost revenue and revenue requirements by class. Monthly fixed charges were adjusted slightly downward for domestic customers reflecting the downward adjustment resulting from EPMC without customer costs. Monthly fixed charges were adjusted slightly upward for non-domestic class. We were again able to set the per-kWh charges at the relevant marginal cost level.

Appendix Table B.32: 2018 Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	40.45	40.45	40.45	38.42	27.37
(3)	Winter off-peak	13.97	13.97	13.97	12.73	12.32
(4)	Summer peak	8.75	8.75	8.75	8.34	7.81
(5)	Summer off-peak	5.18	5.18	5.18	4.87	4.61
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	1,151	1,151	8,205	129,786	752,159
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		40.45	40.45	38.42	27.37
(8)	Winter off-peak		13.97	13.97	12.73	12.32
(9)	Winter weighted average	36.48				
(10)	Summer peak		8.75	8.75	8.34	7.81
(11)	Summer off-peak		5.18	5.18	4.87	4.61
(12)	Summer weighted average	8.22				

B.8.3 Class Revenue Allocation and Marginal Cost-Based Tariff Structure for 2021

In 2021 the new generation capacity is reflected in the revenue requirement, resulting in a large increase, while marginal costs fall. In all investment scenarios, we used the modified EPMC revenue allocation approach to cushion somewhat the domestic class's increase. The comparison of marginal cost revenue to the revenue requirement for 2021 for all the eight investments scenarios are shown in Appendix Table B.33 to Appendix Table B.40.

Appendix Table B.33: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Gas Concessional Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	59,263,490,523	28,164,371,735	87,427,862,258	63,594,027,435	37,459,453,154	13,277,953,469	201,759,296,317
Ratio of Proposed Revenue to Total Class MC Revenue			172%	267%	256%	215%	
Percent Change from Revenue at Current Tariffs			46%	40%	54%	-9%	

Appendix Table B.34: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Gas + RE Concessional Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	63,358,744,480	30,110,599,570	93,469,344,050	67,988,532,218	40,047,994,133	14,195,492,935	215,701,363,336
Ratio of Proposed Revenue to Total Class MC Revenue			184%	286%	274%	230%	
Percent Change from Revenue at Current Tariffs			56%	49%	64%	-3%	

Appendix Table B.35: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Nuclear Concessional Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	76,778,008,074	36,487,968,249	113,265,976,323	82,388,376,196	48,530,084,397	17,202,071,792	261,386,508,708
Ratio of Proposed Revenue to Total Class MC Revenue			223%	346%	332%	278%	
Percent Change from Revenue at Current Tariffs			89%	81%	99%	18%	

Appendix Table B.36: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Nuclear + RE Concessional Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	83,227,960,173	39,553,242,450	122,781,202,623	89,309,643,018	52,606,990,370	18,647,180,122	283,345,016,133
Ratio of Proposed Revenue to Total Class MC Revenue			241%	375%	360%	302%	
Percent Change from Revenue at Current Tariffs			105%	96%	116%	27%	

Appendix Table B.37: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Gas Commercial Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	70,178,968,873	33,351,841,917	103,530,810,790	75,307,128,090	44,358,942,980	15,723,560,576	238,920,442,436
Ratio of Proposed Revenue to Total Class MC Revenue			204%	316%	303%	254%	
Percent Change from Revenue at Current Tariffs			73%	65%	82%	7%	

Appendix Table B.38: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Gas + RE Commercial Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	77,731,252,299	36,940,987,881	114,672,240,180	83,411,276,448	49,132,614,000	17,415,645,653	264,631,776,281
Ratio of Proposed Revenue to Total Class MC Revenue			225%	350%	336%	282%	
Percent Change from Revenue at Current Tariffs			92%	83%	101%	19%	

Appendix Table B.39: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Nuclear Commercial Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	129,533,426,804	61,559,444,989	191,092,871,792	138,998,770,158	81,875,895,100	29,021,895,244	440,989,432,294
Ratio of Proposed Revenue to Total Class MC Revenue			376%	584%	560%	470%	
Percent Change from Revenue at Current Tariffs			219%	205%	236%	98%	

Appendix Table B.40: Comparison of Current, Marginal Cost and Modified EPMC Revenues by Class (2021 – Nuclear + RE Commercial Scenario)

	Domestic			General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)	TOTAL
	non-TOD	TOD	Combined	TOD	TOD	TOD	
Current Tariff Revenues	40,162,213,422	19,693,236,482	59,855,449,904	45,578,853,985	24,384,938,775	14,638,062,061	144,457,304,725
Marginal Cost Revenues	35,939,793,995	14,922,075,596	50,861,869,591	23,813,815,417	14,622,556,126	6,179,023,117	95,477,264,251
Class Revenue Requirement Using EPMC excluding marginal customer-related costs	147,761,955,229	70,222,367,915	217,984,323,144	158,559,304,419	93,397,840,577	33,105,987,323	503,047,455,463
Ratio of Proposed Revenue to Total Class MC Revenue			429%	666%	639%	536%	
Percent Change from Revenue at Current Tariffs			264%	248%	283%	126%	

In designing the 2021 tariff for all investment scenarios, customer charges were increased above marginal cost by 2 times for domestic customers, 4 times for secondary general service, 4 times for primary generation service and 3 times for 35+ kV service. It would be efficient to recover all of the above-marginal cost revenue in fixed charges, but with a large gap, this would not be feasible in terms of bill impacts. The remaining additional revenue was achieved through the use of fixed increases in the per-kWh charges for each class. The result is per-kWh charges that are well above marginal cost, but retain the marginal cost relationships across the seasons and diurnal periods. The 2021 tariff design for each investment scenario are shown in Appendix Table B.41 to B.48.

Appendix Table B.41: 2021 (Gas Concessional Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		19.06	23.34	19.83	7.36
(8)	Winter off-peak		5.55	9.83	6.93	3.69
(9)	Winter weighted average	17.03				
(10)	Summer peak		5.29	9.57	6.80	3.48
(11)	Summer off-peak		5.20	9.48	6.63	3.40
(12)	Summer weighted average	5.27				

Appendix Table B.42: 2021 (Gas+RE Concessional Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		21.68	25.73	22.00	8.47
(8)	Winter off-peak		8.18	12.23	9.09	4.80
(9)	Winter weighted average	19.66				
(10)	Summer peak		7.91	11.96	8.96	4.59
(11)	Summer off-peak		7.83	11.87	8.80	4.51
(12)	Summer weighted average	7.90				

Appendix Table B.43: 2021 (Nuclear Concessional Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		30.29	33.57	29.09	12.11
(8)	Winter off-peak		16.79	20.07	16.19	8.44
(9)	Winter weighted average	28.27				
(10)	Summer peak		16.52	19.80	16.06	8.23
(11)	Summer off-peak		16.43	19.71	15.89	8.15
(12)	Summer weighted average	16.51				

Appendix Table B.44: 2021 (Nuclear + RE Concessional Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		34.43	37.34	32.50	13.85
(8)	Winter off-peak		20.92	23.83	19.60	10.18
(9)	Winter weighted average	32.40				
(10)	Summer peak		20.66	23.57	19.47	9.97
(11)	Summer off-peak		20.57	23.48	19.30	9.90
(12)	Summer weighted average	20.64				

Appendix Table B.45: 2021 (Gas Commercial Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
	Monthly Marginal Customer-Related Cost					
(1)	(AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		26.06	29.71	25.60	10.32
(8)	Winter off-peak		12.55	16.21	12.70	6.65
(9)	Winter weighted average	24.03				
(10)	Summer peak		12.29	15.94	12.57	6.44
(11)	Summer off-peak		12.20	15.86	12.40	6.36
(12)	Summer weighted average	12.27				

Appendix Table B.46: 2021 (Gas+RE Commercial Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
	Monthly Marginal Customer-Related Cost					
(1)	(AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		30.90	34.13	29.60	12.36
(8)	Winter off-peak		17.40	20.62	16.69	8.69
(9)	Winter weighted average	28.88				
(10)	Summer peak		17.13	20.35	16.56	8.49
(11)	Summer off-peak		17.04	20.27	16.40	8.41
(12)	Summer weighted average	17.12				

Appendix Table B.47: 2021 (Nuclear Commercial Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		64.13	64.39	56.98	26.40
(8)	Winter off-peak		50.62	50.89	44.08	22.73
(9)	Winter weighted average	62.10				
(10)	Summer peak		50.35	50.62	43.95	22.52
(11)	Summer off-peak		50.27	50.53	43.79	22.44
(12)	Summer weighted average	50.34				

Appendix Table B.48: 2021 (Nuclear + RE Commercial Scenario) Tariff Design Based on Marginal Costs

		Domestic		General Service Secondary (0.38kV)	General Service Primary (6(10)kV)	General Service (35+kV)
		non-TOD	TOD	TOD	TOD	TOD
	Marginal Unit Costs					
(1)	Monthly Marginal Customer-Related Cost (AMD/customer/month)	2,522	2,522	7,212	118,145	704,455
	Combined Marginal Energy and Capacity Costs (AMD/kWh)					
(2)	Winter peak	16.44	16.44	16.44	15.58	6.26
(3)	Winter off-peak	2.94	2.94	2.94	2.68	2.59
(4)	Summer peak	2.67	2.67	2.67	2.55	2.38
(5)	Summer off-peak	2.58	2.58	2.58	2.38	2.30
	Proposed Charges					
(6)	Monthly Fixed Cost (AMD/customer/month)	5,044	5,044	28,849	472,580	2,113,364
	Energy Charges (AMD/kWh) Marginal Cost - (25)					
(7)	Winter peak		75.82	75.04	66.62	31.33
(8)	Winter off-peak		62.31	61.54	53.72	27.66
(9)	Winter weighted average	73.79				
(10)	Summer peak		62.05	61.27	53.59	27.45
(11)	Summer off-peak		61.96	61.18	53.42	27.38
(12)	Summer weighted average	62.03				

B.9 Marginal Costs per kW and per kWh for 2014-2021

Appendix Table B.49: Summary Tables of Marginal Costs per kW and per kWh for 2014-2021

		2014				2015				2016			
		Winter		Summer		Winter		Summer		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD)				(2013 AMD)				(2013 AMD)			
		(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
	35 kV and above												
(1)	Energy (per kWh)	17.75	7.48	3.36	1.01	18.31	8.01	3.88	1.14	21.13	12.49	4.60	1.27
(2)	Generation Capacity (per peak period kW-mo.)	503.74	204.70	346.03	157.97	521.53	211.93	358.25	163.55	540.14	219.49	371.04	169.38
(3)	Transmission (per peak period kW-mo.)	1,582.68	0.00	0.43	0.49	1,582.68	0.00	0.43	0.49	1,582.68	0.00	0.43	0.49
(4)	Distribution Substation (per peak period kW-mo.)	-	-	0.00	0.00	-	-	-	-	-	-	-	-
	Total per kW	2,086.42	204.70	346.46	158.46	2,104.21	211.93	358.68	164.04	2,122.82	219.49	371.47	169.87
	6(10) kV direct												
(5)	Energy (per kWh)	19.30	7.58	3.61	1.03	19.91	8.12	4.16	1.16	22.97	12.66	4.94	1.29
(6)	Generation Capacity (per peak period kW-mo.)	535.27	217.51	367.69	167.86	554.18	225.20	380.68	173.78	573.95	233.23	394.26	179.99
(7)	Transmission (per peak period kW-mo.)	1,681.77	0.00	0.46	0.52	1,681.77	0.00	0.46	0.52	1,681.77	0.00	0.46	0.52
(8)	Distribution Substation (per peak period kW-mo.)	4,326.15	0.00	1.18	1.34	4,326.15	0.00	1.18	1.34	4,326.15	0.00	1.18	1.34
	Total per kW	6,543.19	217.51	369.33	169.72	6,562.09	225.20	382.31	175.64	6,581.87	233.23	395.90	181.85
	0.4 kV												
(9)	Energy (per kWh)	20.27	8.55	3.76	1.13	20.92	9.15	4.34	1.27	24.13	14.27	5.14	1.42
(10)	Generation Capacity (per peak period kW-mo.)	565.04	229.61	388.14	177.19	585.00	237.72	401.85	183.45	605.87	246.20	416.19	190.00
(11)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55
(12)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41
	Total per kW	6,907.07	229.61	389.87	179.16	6,927.03	237.72	403.57	185.41	6,947.90	246.20	417.91	191.96
	Residential												
(13)	Energy (per kWh)	20.27	8.55	3.76	1.13	20.92	9.15	4.34	1.27	24.13	14.27	5.14	1.42
(14)	Generation Capacity (per peak period kW-mo.)	565.04	229.61	388.14	177.19	585.00	237.72	401.85	183.45	605.87	246.20	416.19	190.00
(15)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55
(16)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41
	Total per kW	6,907.07	229.61	389.87	179.16	6,927.03	237.72	403.57	185.41	6,947.90	246.20	417.91	191.96

		2017				2018				2019			
		Winter		Summer		Winter		Summer		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD)				(2013 AMD)				(2013 AMD)			
		(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
	35 kV and above												
(1)	Energy (per kWh)	17.42	6.95	2.93	0.69	18.01	7.36	3.62	0.78	18.51	7.93	4.19	0.90
(2)	Generation Capacity (per peak period kW-mo.)	2,632.52	1,069.75	1,808.35	825.53	2,970.40	1,207.05	2,040.44	931.48	3,383.07	1,374.74	2,323.92	1,060.89
(3)	Transmission (per peak period kW-mo.)	1,582.68	0.00	0.43	0.49	1,582.68	0.00	0.43	0.49	1,582.68	0.00	0.43	0.49
(4)	Distribution Substation (per peak period kW-mo.)	-	-	-	-	-	-	-	-	-	-	-	-
	Total per kW	4,215.20	1,069.75	1,808.78	826.02	4,553.08	1,207.05	2,040.87	931.97	4,965.75	1,374.74	2,324.35	1,061.38
	6(10) kV direct												
(5)	Energy (per kWh)	18.94	7.04	3.15	0.70	19.59	7.46	3.88	0.80	20.12	8.04	4.50	0.92
(6)	Generation Capacity (per peak period kW-mo.)	2,797.32	1,136.72	1,921.55	877.21	3,156.35	1,282.62	2,168.18	989.80	3,594.86	1,460.81	2,469.40	1,127.31
(7)	Transmission (per peak period kW-mo.)	1,681.77	0.00	0.46	0.52	1,681.77	0.00	0.46	0.52	1,681.77	0.00	0.46	0.52
(8)	Distribution Substation (per peak period kW-mo.)	4,326.15	0.00	1.18	1.34	4,326.15	0.00	1.18	1.34	4,326.15	0.00	1.18	1.34
	Total per kW	8,805.24	1,136.72	1,923.19	879.07	9,164.27	1,282.62	2,169.81	991.66	9,602.77	1,460.81	2,471.03	1,129.17
	0.4 kV												
(9)	Energy (per kWh)	19.89	7.94	3.28	0.77	20.58	8.40	4.05	0.88	21.14	9.06	4.69	1.01
(10)	Generation Capacity (per peak period kW-mo.)	2,952.89	1,199.94	2,028.42	925.99	3,331.88	1,353.95	2,288.76	1,044.84	3,794.77	1,542.05	2,606.73	1,190.00
(11)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55
(12)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41
	Total per kW	9,294.92	1,199.94	2,030.14	927.96	9,673.91	1,353.95	2,290.48	1,046.81	10,136.80	1,542.05	2,608.45	1,191.96
	Residential												
(13)	Energy (per kWh)	19.89	7.94	3.28	0.77	20.58	8.40	4.05	0.88	21.14	9.06	4.69	1.01
(14)	Generation Capacity (per peak period kW-mo.)	2,952.89	1,199.94	2,028.42	925.99	3,331.88	1,353.95	2,288.76	1,044.84	3,794.77	1,542.05	2,606.73	1,190.00
(15)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55
(16)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41
	Total per kW	9,294.92	1,199.94	2,030.14	927.96	9,673.91	1,353.95	2,290.48	1,046.81	10,136.80	1,542.05	2,608.45	1,191.96

		2020				2021			
		Winter		Summer		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD)				(2013 AMD)			
		(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
	35 kV and above								
(1)	Energy (per kWh)	20.39	12.60	4.83	1.00	1.69	1.52	1.47	1.47
(2)	Generation Capacity (per peak period kW-mo.)	3,919.71	1,592.82	2,692.55	1,229.18	642.99	261.28	441.68	201.63
(3)	Transmission (per peak period kW-mo.)	1,582.68	0.00	0.43	0.49	1,582.68	0.00	0.43	0.49
(4)	Distribution Substation (per peak period kW-mo.)	-	-	-	-	-	-	-	-
	Total per kW	5,502.39	1,592.82	2,692.98	1,229.67	2,225.67	261.28	442.11	202.12
	6(10) kV direct								
(5)	Energy (per kWh)	22.17	12.77	5.18	1.02	1.84	1.54	1.58	1.50
(6)	Generation Capacity (per peak period kW-mo.)	4,165.10	1,692.53	2,861.11	1,306.13	683.24	277.64	469.33	214.26
(7)	Transmission (per peak period kW-mo.)	1,681.77	0.00	0.46	0.52	1,681.77	0.00	0.46	0.52
(8)	Distribution Substation (per peak period kW-mo.)	4,326.15	0.00	1.18	1.34	4,326.15	0.00	1.18	1.34
	Total per kW	10,173.01	1,692.53	2,862.75	1,307.99	6,691.15	277.64	470.97	216.12
	0.4 kV								
(9)	Energy (per kWh)	23.29	14.39	5.40	1.12	1.93	1.73	1.65	1.65
(10)	Generation Capacity (per peak period kW-mo.)	4,396.73	1,786.66	3,020.23	1,378.76	721.24	293.08	495.44	226.17
(11)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55
(12)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41
	Total per kW	10,738.76	1,786.66	3,021.95	1,380.73	7,063.27	293.08	497.16	228.14
	Residential								
(13)	Energy (per kWh)	23.29	14.39	5.40	1.12	1.93	1.73	1.65	1.65
(14)	Generation Capacity (per peak period kW-mo.)	4,396.73	1,786.66	3,020.23	1,378.76	721.24	293.08	495.44	226.17
(15)	Transmission (per peak period kW-mo.)	1,775.29	0.00	0.48	0.55	1,775.29	0.00	0.48	0.55
(16)	Distribution Substation (per peak period kW-mo.)	4,566.74	0.00	1.24	1.41	4,566.74	0.00	1.24	1.41
	Total per kW	10,738.76	1,786.66	3,021.95	1,380.73	7,063.27	293.08	497.16	228.14

B.10 Marginal Costs with Capacity Costs Stated on a per-kWh Basis for 2014-2021

Appendix Table B.50: Summary Tables of Marginal Costs with Capacity Costs Stated on a per-kWh Basis for 2014-2021

		2014				2015				2016			
		Winter		Summer		Winter		Summer		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD per kWh)				(2013 AMD per kWh)				(2013 AMD per kWh)			
		(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
	35 kV and above												
(1)	Energy	17.75	7.48	3.36	1.01	18.31	8.01	3.88	1.14	21.13	12.49	4.60	1.27
(2)	Generation Capacity	$1.04	$0.84	$0.71	$0.65	$1.07	$0.87	$0.74	$0.67	$1.11	$0.90	$0.76	$0.70
(3)	Transmission	$3.25	$0.00	$0.00	$0.00	$3.25	$0.00	$0.00	$0.00	$3.25	$0.00	$0.00	$0.00
(4)	Distribution Substation	-	-	-	-	-	-	-	-	-	-	-	-
	Total	$22.04	$8.32	$4.08	$1.66	$22.64	$8.88	$4.62	$1.81	$25.49	$13.39	$5.37	$1.97
	6(10) kV direct												
(5)	Energy	19.30	7.58	3.61	1.03	19.91	8.12	4.16	1.16	22.97	12.66	4.94	1.29
(6)	Generation Capacity	$1.10	$0.89	$0.76	$0.69	$1.14	$0.93	$0.78	$0.71	$1.18	$0.96	$0.81	$0.74
(7)	Transmission	$3.46	$0.00	$0.00	$0.00	$3.46	$0.00	$0.00	$0.00	$3.46	$0.00	$0.00	$0.00
(8)	Distribution Substation	$8.89	$0.00	$0.00	$0.01	$8.89	$0.00	$0.00	$0.01	$8.89	$0.00	$0.00	$0.01
	Total	$32.75	$8.48	$4.37	$1.72	$33.40	$9.05	$4.95	$1.88	$36.50	$13.62	$5.75	$2.04
	0.4 kV												
(9)	Energy	20.27	8.55	3.76	1.13	20.92	9.15	4.34	1.27	24.13	14.27	5.14	1.42
(10)	Generation Capacity	$1.16	$0.94	$0.80	$0.73	$1.20	$0.98	$0.83	$0.75	$1.24	$1.01	$0.86	$0.78
(11)	Transmission	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00
(12)	Distribution Substation	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01
	Total	$34.47	$9.49	$4.56	$1.86	$35.15	$10.13	$5.17	$2.04	$38.41	$15.28	$6.00	$2.21
	Residential												
(13)	Energy	20.27	8.55	3.76	1.13	20.92	9.15	4.34	1.27	24.13	14.27	5.14	1.42
(14)	Generation Capacity	$1.16	$0.94	$0.80	$0.73	$1.20	$0.98	$0.83	$0.75	$1.24	$1.01	$0.86	$0.78
(15)	Transmission	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00
(16)	Distribution Substation	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01
	Total	$34.47	$9.49	$4.56	$1.86	$35.15	$10.13	$5.17	$2.04	$38.41	$15.28	$6.00	$2.21

		2017				2018				2019			
		Winter		Summer		Winter		Summer		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD per kWh)				(2013 AMD per kWh)				(2013 AMD per kWh)			
		(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
	35 kV and above												
(1)	Energy	17.42	6.95	2.93	0.69	18.01	7.36	3.62	0.78	18.51	7.93	4.19	0.90
(2)	Generation Capacity	$5.41	$4.40	$3.72	$3.39	$6.10	$4.96	$4.19	$3.83	$6.95	$5.65	$4.78	$4.36
(3)	Transmission	$3.25	$0.00	$0.00	$0.00	$3.25	$0.00	$0.00	$0.00	$3.25	$0.00	$0.00	$0.00
(4)	Distribution Substation	-	-	-	-	-	-	-	-	-	-	-	-
	Total	$26.08	$11.34	$6.65	$4.08	$27.37	$12.32	$7.81	$4.61	$28.71	$13.58	$8.97	$5.27
	6(10) kV direct												
(5)	Energy	18.94	7.04	3.15	0.70	19.59	7.46	3.88	0.80	20.12	8.04	4.50	0.92
(6)	Generation Capacity	$5.75	$4.67	$3.95	$3.60	$6.49	$5.27	$4.46	$4.07	$7.39	$6.00	$5.07	$4.63
(7)	Transmission	$3.46	$0.00	$0.00	$0.00	$3.46	$0.00	$0.00	$0.00	$3.46	$0.00	$0.00	$0.00
(8)	Distribution Substation	$8.89	$0.00	$0.00	$0.01	$8.89	$0.00	$0.00	$0.01	$8.89	$0.00	$0.00	$0.01
	Total	$37.03	$11.71	$7.10	$4.31	$38.42	$12.73	$8.34	$4.87	$39.85	$14.04	$9.58	$5.56
	0.4 kV												
(9)	Energy	19.89	7.94	3.28	0.77	20.58	8.40	4.05	0.88	21.14	9.06	4.69	1.01
(10)	Generation Capacity	$6.07	$4.93	$4.17	$3.81	$6.85	$5.56	$4.70	$4.29	$7.80	$6.34	$5.36	$4.89
(11)	Transmission	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00
(12)	Distribution Substation	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01
	Total	$38.99	$12.87	$7.45	$4.58	$40.45	$13.97	$8.75	$5.18	$41.97	$15.40	$10.05	$5.91
	Residential												
(13)	Energy	19.89	7.94	3.28	0.77	20.58	8.40	4.05	0.88	21.14	9.06	4.69	1.01
(14)	Generation Capacity	$6.07	$4.93	$4.17	$3.81	$6.85	$5.56	$4.70	$4.29	$7.80	$6.34	$5.36	$4.89
(15)	Transmission	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00
(16)	Distribution Substation	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01
	Total	$38.99	$12.87	$7.45	$4.58	$40.45	$13.97	$8.75	$5.18	$41.97	$15.40	$10.05	$5.91

		2020				2021			
		Winter		Summer		Winter		Summer	
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
		(2013 AMD per kWh)				(2013 AMD per kWh)			
		(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
	35 kV and above								
(1)	Energy	20.39	12.60	4.83	1.00	1.69	1.52	1.47	1.47
(2)	Generation Capacity	$8.05	$6.55	$5.53	$5.05	$1.32	$1.07	$0.91	$0.83
(3)	Transmission	$3.25	$0.00	$0.00	$0.00	$3.25	$0.00	$0.00	$0.00
(4)	Distribution Substation	-	-	-	-	-	-	-	-
	Total	$31.69	$19.14	$10.36	$6.06	$6.26	$2.59	$2.38	$2.30
	6(10) kV direct								
(5)	Energy	22.17	12.77	5.18	1.02	1.84	1.54	1.58	1.50
(6)	Generation Capacity	$8.56	$6.96	$5.88	$5.37	$1.40	$1.14	$0.96	$0.88
(7)	Transmission	$3.46	$0.00	$0.00	$0.00	$3.46	$0.00	$0.00	$0.00
(8)	Distribution Substation	$8.89	$0.00	$0.00	$0.01	$8.89	$0.00	$0.00	$0.01
	Total	$43.07	$19.72	$11.06	$6.39	$15.58	$2.68	$2.55	$2.38
	0.4 kV								
(9)	Energy	23.29	14.39	5.40	1.12	1.93	1.73	1.65	1.65
(10)	Generation Capacity	$9.03	$7.34	$6.21	$5.67	$1.48	$1.20	$1.02	$0.93
(11)	Transmission	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00
(12)	Distribution Substation	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01
	Total	$45.35	$21.73	$11.61	$6.80	$16.44	$2.94	$2.67	$2.58
	Residential								
(13)	Energy	23.29	14.39	5.40	1.12	1.93	1.73	1.65	1.65
(14)	Generation Capacity	$9.03	$7.34	$6.21	$5.67	$1.48	$1.20	$1.02	$0.93
(15)	Transmission	$3.65	$0.00	$0.00	$0.00	$3.65	$0.00	$0.00	$0.00
(16)	Distribution Substation	$9.38	$0.00	$0.00	$0.01	$9.38	$0.00	$0.00	$0.01
	Total	$45.35	$21.73	$11.61	$6.80	$16.44	$2.94	$2.67	$2.58