December 23, 2025

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: Newfoundland Power Customer, Energy & Demand Forecast ("CED Forecast") Review

On June 6, 2024, a settlement agreement between Newfoundland Power Inc. ("Newfoundland Power" or the "Company"), the Consumer Advocate, Newfoundland and Labrador Hydro, the International Brotherhood of Electrical Workers, Local 1620 and Board Hearing Counsel was filed with the Board (the "Settlement Agreement") in relation to Newfoundland Power's 2025/2026 General Rate Application ("2025/2026 GRA"). The Settlement Agreement addressed a range of issues arising from the 2025/2026 GRA.[1]

As part of the Settlement Agreement, the parties agreed that, as proposed in the 2025/2026 GRA, the Board should approve the CED Forecast. The parties also agreed that Newfoundland Power should engage an expert to conduct a review of the recommendations set out in the Brattle Group Load Forecasting Methodology Review (the "Brattle Review").[2] The Board accepted the Settlement Agreement recommendation and directed Newfoundland Power to file a report in relation to the CED Forecast methodology, including the review of the recommendations set out in the Brattle Review, on or before December 31, 2025 (the "CED Forecast Review").[3]

Newfoundland Power engaged Daymark Energy Advisors ("Daymark") to complete the CED Forecast Review. Daymark participated in a weeklong, in-person workshop at Newfoundland Power to review the CED Forecast model and methodology ahead of completing its assessment. The CED Forecast Review included Newfoundland Power's energy forecasting models for the Company's Domestic, General Service, and Street and Area Lighting customer rate classes. It also included a review of the Company's demand forecasting methodology.

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1 See Order No. P.U. 3 (2025), page 5, lines 5-9.
2 Ibid, page 12 line 37 to page 13 line 26.
3 Ibid.

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Following its assessment, Daymark determined that Newfoundland Power's CED Forecast is reasonable and that error rates were within acceptable levels.[4] Daymark recommended Newfoundland Power enhance its CED Forecast regulatory reporting which would provide more information and greater clarity during a GRA process. Daymark also recommended Newfoundland Power adopt a new statistical software package that would better facilitate model sensitivity analysis and testing. In addition, Daymark identified possible model specification adjustments and provided other suggestions that should be considered for future testing and forecasts. Finally, Daymark reviewed and responded to each of the recommendations provided in the Brattle Review.

Please find enclosed the Daymark report *Newfoundland Power Inc.: Load Forecast Review, December 19, 2025.* Newfoundland Power will use the results and insights gained from the Load Forecast Review to further enhance its CED Forecast for future forecast periods and to provide greater clarity of the Company's forecasting methodology and models as part of future general rate applications.

If there are any questions concerning the foregoing, please contact the undersigned.

Yours truly,

Dominic Foley
Legal Counsel

Enclosures

ec. Shirley Walsh
Newfoundland and Labrador Hydro

Steven Stewart
International Brotherhood of Electrical Workers, Local 1620

Dennis Browne, K.C.
Browne Fitzgerald Morgan and Avis

4 Daymark *Newfoundland Power Inc.: Load Forecast Review, December 19, 2025*, page 1.

NEWFOUNDLAND POWER INC.: LOAD FORECAST REVIEW

DECEMBER 19, 2025

PREPARED FOR

Newfoundland Power Inc.

PREPARED BY

Daymark Energy Advisors

DAYMARK ENERGY ADVISORS

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LIST OF ACRONYMS

ADF	Augmented Dickey Fuller
CAGR	Compound Annual Growth Rate
CBOC	Conference Board of Canada
CDM	Conservation and Demand Management
CED	Customer, energy and demand
CO2	Carbon dioxide
CPI	Consumer Price Index
DSM	Demand-side management
GDP	Gross Domestic Product
GRA	General Rate Application
GW	Gigawatt
GWh	Gigawatt-hour
HCG	Housing to customer growth
HPS	High-pressure sodium
kW	Kilowatt
kWh	Kilowatt-hour
LGS	Large General Service
MAPE	Mean absolute percentage errors
MMBtu	Million British thermal units
MSHP	Mini-split heat pump
MW	Megawatt
MWh	Megawatt-hour
OLS	Ordinary least squares
PUB	Newfoundland and Labrador Board of Commissioners of Public Utilities
SGS	Small General Service
SGSS	Small General Service Sales
VIF	Variance Inflation Factor

DISCLAIMER

The analyses supporting the results presented here involve the use of assumptions and projections with respect to conditions that may exist or events that may occur in the future. Although Daymark Energy Advisors has applied assumptions and projections that are believed to be reasonable, they are subjective and may differ from those that might be used by other economic or industry experts to perform similar analysis. In addition, actual future outcomes are dependent upon future events that are outside Daymark Energy Advisors' control. Daymark Energy Advisors cannot, and does not, accept liability under any theory for losses suffered, whether direct or consequential, arising from any reliance on this presentation, and cannot be held responsible if any conclusions drawn from this presentation should prove to be inaccurate.

I. EXECUTIVE SUMMARY

Daymark Energy Advisors ("Daymark") were engaged by Newfoundland Power Inc. ("Newfoundland Power" or "Company") to review the Customer, Energy and Demand ("CED") Forecast for its 2025/2026 General Rate Application ("GRA") which was finalized by Newfoundland Power in September 2023. The CED Forecast was initially reviewed by The Brattle Group ("Brattle") and while the forecast was deemed reasonable and was approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB"), Brattle made several recommendations concerning changes to the methodology that Newfoundland Power should take into consideration for load forecasts in future GRAs. Following the Brattle report, the PUB requested Newfoundland Power engage an expert to conduct an additional review of its CED Forecast methodology.

A full assessment of the CED Forecast was carried out, with Daymark migrating the econometric forecast models to the R statistical programming environment and systematically carrying out various sensitivity analyses to explore the models' validity, performance, and reliability. Daymark determined that the CED Forecast is reasonable and that error rates were within acceptable levels.

With regards to Brattle's recommendations, Daymark agreed that additional detail should be provided in regulatory reporting, including assumptions and model parameters. A more detailed report would assist the PUB and interested parties in understanding Newfoundland Power's CED process and results, and would lead to a more efficient review process.

Focusing on specific Brattle recommendations, Daymark determined the following:

1. Newfoundland Power has not systematically under-forecast energy sales. However, continued testing and reporting of forecast accuracy should be part of a more detailed CED report.

2. The use of weather normalized historical consumption data accounts for the impacts of weather in Newfoundland Power's forecast. However, an alternative method of using actual historical data including monthly CDD, HDD, or other constructions of weather variables could assist Newfoundland Power in testing forecast sensitivities related to weather. Given the general accuracy of the CED Forecast and the requirement for Newfoundland Power to move to monthly

forecasting models, it is unclear that shifting to this approach would necessarily improve model performance.

3. There is not sufficient evidence of endogeneity problems relating to the exclusion of oil prices given fuel switching trends in the province, driven both by government incentives for oil-to-electric heating conversions as well as general customer preference for electric heating among new customers.

Overall, Daymark agrees with Brattle that Newfoundland Power should incorporate additional testing in its forecasting process to determine the degree to which some recommendations, such as accounting for demand-side management in its peak demand forecast or using alternative regression model specifications, would ultimately have on forecast accuracy, and whether the additional time/cost of these changes is justified given its historical accuracy.

Following Daymark's analyses, several recommendations are provided to improve the methodology and defensibility of the Company's future forecasts:

1. Whereas Newfoundland Power has traditionally used Microsoft Excel to run all of its forecasting models, Daymark recommends the use of R, eViews, or Python. These statistical software programs would provide Newfoundland Power with additional functionality and insight into its forecast models.

2. Establish a repeatable testing and validation regime to allow for iterative improvements in forecast performance and accuracy.

3. Expand the level of detail in regulatory reporting to the PUB, including the results of testing and validation exercises, and providing additional details about the philosophy behind the methodology.

4. Test and consider elimination of the 2022+ variable from the model, examining how this vintage of the model performs against actuals in 2023 and 2024.

5. Identify clear reasons for variable transformations. Newfoundland Power should test how re-specifying model variables impacts its forecast and review its independent variables to ensure that they are specified in units that are easily interpretable.

II. BACKGROUND/CONTEXT

A. Goals of Newfoundland Power Forecast

Newfoundland Power Inc. ("Newfoundland Power" or "Company") provides electricity and customer service delivery in its service territory on the island portion of Newfoundland and Labrador. Electricity in this service territory is primarily supplied by Newfoundland and Labrador Hydro ("Hydro"), after which electricity is purchased by Newfoundland Power for distribution. Newfoundland Power also owns some minor generation assets, distributed across its service territory.

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB"). Every year Newfoundland Power files a Capital Budget Application with the PUB to approve capital expenditures, and approximately every three years a General Rate Application ("GRA") is filed, as shown in Figure 1.

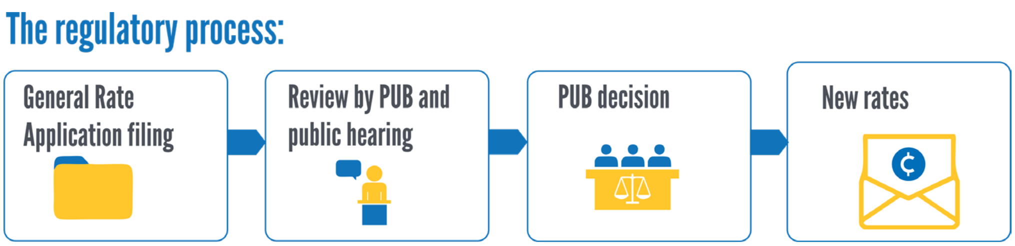


Figure 1: Newfoundland Power Rate Setting Procedure (Source: Newfoundland Power)

Newfoundland Power's Customer, Energy and Demand ("CED") Forecast is prepared annually, and is a key input into Newfoundland Power's Capital Budget Applications and GRAs. It provides a forecast of customers, energy sales and peak demand which is used to forecast revenue and electricity purchases from Hydro. The CED Forecast is required for capital planning and establishing customer rates that recover Newfoundland Power's costs. The CED Forecast is also an input used by Hydro to forecast electricity requirements on the Island Interconnected System.

B. Details of the 2025/2026 GRA Proceeding

The CED Forecast from Newfoundland Power's most recent 2025/2026 GRA was reviewed by the Brattle Group ("Brattle"). The previous review by Brattle concluded that Newfoundland Power's CED Forecast provides reasonable accuracy for the 2025/2026 GRA. They predict, however, that accuracy levels are likely to worsen in the future based on critiques of the Company's forecasting methodology, offering several recommendations on how to improve forecasting going forward.

In the Settlement Agreement filed in relation to the 2025/2026 GRA, it was agreed that Newfoundland Power should engage an expert to conduct a review of the CED Forecast methodology including a review of the recommendations set out in the Brattle review.

Daymark Energy Advisors ("Daymark") has subsequently been hired to provide a review of the CED Forecast and to assess the reasonableness of the employed methodology, to evaluate Brattle's recommendations, and to provide any additional recommendations that would improve the CED Forecast going forward.

In this report, Daymark first offers an assessment of Newfoundland Power's forecasting methodology, including the approach to modeling. A description of Daymark's analysis follows, including discussion of the various sensitivities that were applied to the forecasting model. Finally, a discussion of Brattle's recommendations is provided, with Daymark offering opinions on the impact that each has on the quality of load forecasting and recommendations to Newfoundland Power on a reasonable approach to addressing the Brattle recommendations.

III. NEWFOUNDLAND POWER FORECASTING METHODOLOGY

Load forecasting in the utility industry relies on a variety of standard approaches including the use of time series models, linear regression, end-use modeling, reliance on large customer projections, and often combinations thereof. The selection of model approach relies on data availability, the expert judgment of the forecasters, and rigorous periodic testing to ensure alignment of methodology, costs and results. Daymark participated in a weeklong, in-person workshop at the Newfoundland Power offices in St. John's, NL to review the CED Forecast model and methodology ahead of completing this assessment.

Newfoundland Power regularly produces a CED Forecast as part of a GRA. The CED Forecast produces separate forecasts for each rate class and accumulates those into a final utility level forecast of customer count, annual energy consumption, and peak demand within its service territory. Consistent with good utility practice, Newfoundland Power employs multiple methodologies, including econometric regression, end-use modelling, historical average analysis, and economic accounting. These forecasting methodologies are used to estimate the needs of the Residential, Small General Service, and Street Lighting classes. Large Customer classes are handled separately, primarily on a per-customer basis due to the relatively small size of the class.

In some instances, particularly for the Residential class, Newfoundland Power employs multiple external adjustments to account for novel trends for which data is limited or highly sensitive to policy or other exogenous factors. These include trends such as heat pump adoption, electric vehicle adoption, oil-to-electric heating conversions, and conservation and demand management (“CDM”).

The data underlying Newfoundland Power’s forecast is primarily based on data and forecasts provided by the Conference Board of Canada (“CBOC”) and historical data directly observed by Newfoundland Power. In some instances, Newfoundland Power uses studies by external consultants to examine the evolution of novel trends such as heat pump adoption.

A. Forecast Results

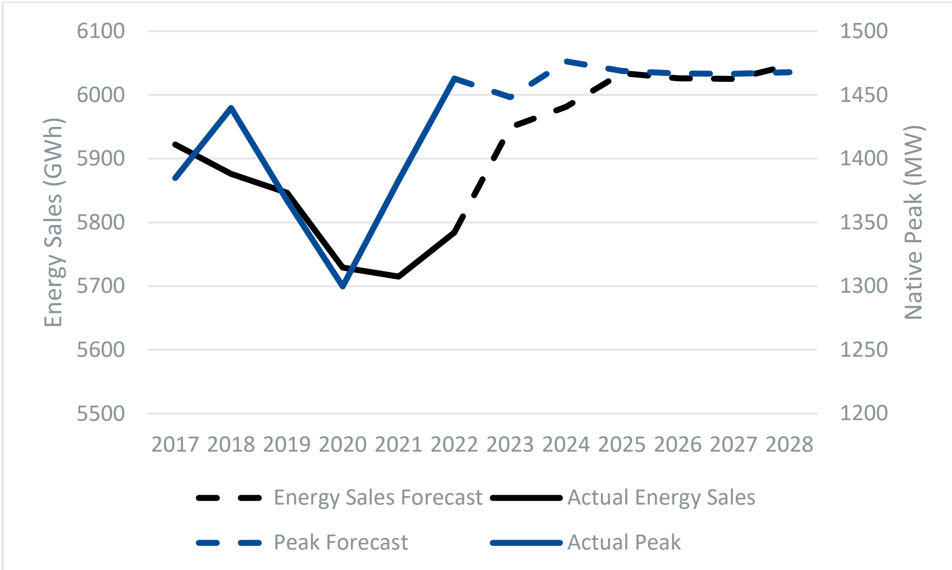
From 2022 through 2028, Newfoundland Power’s September 2023 Forecast shows system energy sales are expected to grow at 0.74% compounded annually, representing an average annual sales growth of approximately 44 GWh.[1] This growth represents a departure from the historical energy sales growth of -0.47% compounded annually from 2017 through 2022, representing an average annual decline of approximately 28 GWh.

In the September 2023 Forecast, peak demand was expected to grow on a weather normalized basis at approximately 0.17% compounded annually, representing an average peak demand growth of approximately 2.5 MW per year over the forecast period.

Actual and forecasted growth trends are summarized in Figure 2 below.

[1] Calculated relative to weather normalized actual sales in 2022.

Figure 2: Summary of Weather Adjusted Energy and Demand Forecast



Forecasted growth is primarily driven by growth in the Large General Service and Residential Basic service categories, as demonstrated in Table 1 below.

Table 1: Drivers of Forecasted Growth from 2022 through 2028

Class	Sales Growth (GWh)	%
Residential		
Regular	91.46	35%
Seasonal	(0.04)	0%
General Service		
0-10 kW	3.77	1%
10-100 kW	21.23	8%
110-1000 kVA	35.89	14%
Over 1000 kVA	120.63	46%
Street Lighting		
All	(11.15)	-4%
Total	261.80	100%

Table 2: Historical (2017-2022) vs Forecasted (2023-2028) Customer Growth

Growth (Customer Count)		
	Historical	Forecast
Class	**(2017-2022)**	**(2023-2028)**
Residential		
Regular	7,104	4,758
Seasonal	(390)	-
General Service		
0-10 kW	408	479
10-100 kW	139	152
110-1000 kVA	(8)	15
Over 1000 kVA	(2)	(2)
Street Lighting		
All	63	335
Total	7,314	5,737

Table 2 above compares the historical growth versus the forecasted growth from the Newfoundland Power CED model. Across all rate classes on a customer count basis, growth is expected to slow down, with residential growth forecasted to slow down the most.

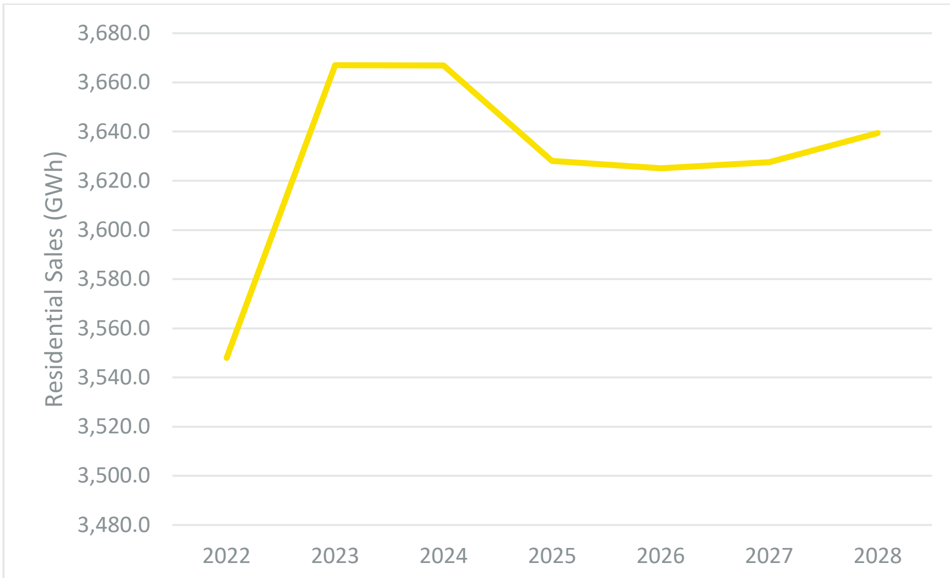
B. Model Structure - Overview

Newfoundland Power employs a variety of techniques to produce its CED Forecast, including econometric regressions, end-use modelling, survey-based modelling, and external adjustments. The selected methodology varies depending on the class or forecast component. The utility uses multiple models for each class—Residential, General Service, and Street Lighting—selected based on data availability as well as characteristics of the class.

C. Residential Sales

Residential Sales are calculated based on the product of a forecasted count of residential customers and forecasted residential average use. Forecasted residential average use is predominantly produced by an econometric regression model, although Newfoundland Power applies multiple external adjustments for novel or data-limited trends such as electric vehicle growth, CDM, heat pump adoption, oil-to-electric heating conversions, and reconciliations with year-to-date actuals observed prior to forecast submission. As shown in Figure 3, Residential Sales were forecasted to remain generally stable across the forecast horizon, increasing at a compound annual growth rate ("CAGR") of 0.42%.

Figure 3: Residential Sales Forecast (GWh)



Residential Customers

Newfoundland Power's Residential Customer forecast methodology is primarily based on forecasted housing development data sourced from the CBOC.

First, Newfoundland Power takes the average of Housing Starts and Housing Completions in Newfoundland and Labrador, as forecasted by the CBOC. This average housing value ("Forecasted Housing") is compared to the net customer increase in a given year to produce a Housing to Customer Growth Ratio ("HCG Ratio"). The Company uses the three-year average of this HCG Ratio as its expected value throughout the forecast period. This ratio is applied to Forecasted Housing to produce an annual forecast of Customer increases. For the September 2023 Forecast, the HCG Ratio was ~107.5%, such that a Forecasted Housing increase of 1000 Dwellings would result in a Net Customer Increase of 1,075 Residential customers.

The annual expected Net Customer Increase is allocated to each of the eight service areas based on a five-year average of sales data ("Zonal Apportionment Factor").[2] By

[2] The eight service areas refer to St. John's, Avalon, Burin, Bonavista, Gander, Grand Falls, Corner Brook, and Stephenville.

adding this value to the recorded number of Residential Customers, Newfoundland Power produces a "Net Residential Customer" forecast.

This forecast is then adjusted for Non-Dwelling and Cottage customers which also take service in this class.[3] Forecasted growth factors for these customer types is based on a five-year ratio of growth relative to Net Residential Customer growth. These growth factors are then applied to the expected Net Residential Customers in a given forecast year to produce the expected level of Non-Dwellings and Cottages taking service. For example, the St. John's Area growth factors were 0.093 for Dwellings and 0.007 for Non-Dwellings and Cottages, respectively. This results in 9 Non-Dwellings and 1 Cottage, respectively, per 100 Net Residential Customers.

Forecasted levels of Net Residential Customers, Non-Dwellings, and Cottages are added for each service area in each year to produce the final customer forecast. The Residential Customer Forecast in a given year can be summarized by the following set of equations, where z = each service area zone, and t = each year:

Equation 1:

$$Net\ Residential\ Customers_{z,t} = Existing\ Residential\ Customers_{z,t} + (Forecasted\ Housing_t * HCG\ Ratio) * Zonal\ Apportionment\ Factor_z$$

Equation 2

$$Total\ Residential\ Customers_{z,t} = Non\ Dwellings_{z,t} + Cottages_{z,t} + Net\ Residential\ Customers_{z,t}$$

Residential Average Use

Residential Average Use is estimated through an econometric regression that uses input data for the years 1980 through 2022 to forecast average use for the following five years. The independent variables used are the penetration of electric heating, a marginal price index, a one-year lagged marginal price index, an index representing cumulative historical CDM, income per capita, a dummy variable for years 2022 onward, and a dummy variable for the year 2020 using input data for the years 1980 through 2022. A summary of this model is presented in Equation 3 and Table 3 below:

[3] Non-dwelling structures are typically residential sheds, garages, or other structures that have a separate electrical service from the main dwelling.

Equation 3: Residential Average Usage Model Specification

$$Average\ Usage_t = \beta_1 Market\_Share_t + \beta_2 Marginal\_Price_t + \beta_3 Marginal\_Price_{t-1} + \beta_4 CDM_t + \beta_5 Income_t + \delta_1 D_{2022} + \delta_2 D_{2020} + \varepsilon_t$$

Table 3: Residential Average Usage Regression Results[4]

	Dependent Var:
Note: ***** p < 0.001; ** p < 0.01; * p < 0.05.**	Residential Average Usage
Market Share	18665.130***
	(533.143)
Marginal Price[5]	-25.396***
	(6.573)
Lag Marginal Price	-17.699*
	(6.933)
CDM Index	-101.425***
	(6.369)
2022+	325.121
	(219.9)
Income/Cust	3.648
	(4.351)
2020	356.497
	(204.594)
Constant	8909.256***
	(484.945)
Observations	43
R^2	0.983
Adj R^2	0.980
Residual SE	174.909 (df = 7; 35)
F Statistic	290.533*** (df = 7; 35)

Independent Variables

The Market Share variable represents the results of an electric heating market share model, developed by Newfoundland Power. It reflects the proportion of residential

[4] Further summary statistics and residual charts are available in Appendix A, Section I.A

[5] Note that the Marginal Price and Lag Marginal Price variables have not been discounted here.

customers that use electricity as their primary heating source. Further details on the construction of the Market Share model are provided in the following section.

The Marginal Price Index represents the Marginal Residential Historical Electric Price, indexed to 2002 to account for inflation. The inflation adjustment is based on Consumer Price Index ("CPI") data and forecasts produced by CBOC. Newfoundland Power expects that higher electricity rates result in reduced consumption of electricity.

The Lagged Marginal Price Index uses a one-year lag of the Marginal Price Index. This variable is intended to capture the delayed effects of rate increases on electricity usage. Newfoundland Power expects that there are both immediate and delayed customer responses to electricity rate increases.

Newfoundland Power determined that the impact of the marginal price variables was too high in consideration of the strong residential energy sales growth in 2022 and 2023 and discounted these coefficients by 20%, such that only 80% of the coefficient values were used to forecast average use. This had the effect of increasing Newfoundland Power's residential energy sales forecast. As such, the coefficients used for forecasting purposes were approximately -20.32 for Marginal Price Index and approximately -14.16 for Lagged Marginal Price Index.

The CDM Index represents cumulative energy savings from CDM programs, indexed to a base year of 1992 due to data availability. Throughout the forecast period, this value is held constant at the prior year's observed CDM Index value, with forecasted CDM captured through an external adjustment.

Income per capita captures real income indexed to 2002 to account for inflation. Newfoundland Power includes this variable to account for economic growth, expecting that higher incomes would result in a higher demand for electricity consumption.

The 2022+ dummy variable captures all years from 2022 through the forecast period. Newfoundland Power included this to establish the base year of the forecast and capture the most recent trends in energy usage. This variable was included since the forecast for the 2025/2026 GRA was completed in 2023 without a full year of actual energy sales data.

The 2020 dummy variable captures the year 2020, reflecting the impacts of the COVID-19 pandemic and related impacts. Social distancing and related policies during this period forced more customers to stay at home, increasing residential energy usage. This variable ensures that transient impacts from 2020 are not extrapolated to the remainder of the forecast period.

External Adjustments

Once Newfoundland Power forecasts sales based on its Average Usage and Customer regression models, it applies multiple external adjustments to the sales forecast. These adjustments do not use econometric methods to develop forecasts, rather using historical data, technical knowledge, and various assumptions to model how novel trends are anticipated to affect usage in the forecast period. It is commonly accepted practice for utilities to use external adjustments to capture trends that are not well documented in historical data or are otherwise difficult to capture via econometric models. Growth of electric vehicle adoption, for example, is a common external adjustment used across multiple utilities in North America.

Electric Heating Market Share Model

Newfoundland Power has an Electric Heating Market Share model to subdivide new customers into electric heat and non-electric heat. The Company defines the Market Share variable as the ratio of Electric Heating Customers to Total Customers. The Market Share forecast relies on the forecast of Gross Connections.

The Gross Connections forecast includes the Net Customer Increase and assumes that all disconnections each year are reconnected. Disconnections are based on a five-year average rate with the assumption that 75% are Non-Electric Heating Customers. The 90% penetration rate of electric heat is assumed for new customer connections.[6] As a result, Newfoundland Power produces a 6-year forecast of Electric and Non-Electric Customer Connections.

The ratio of Electric Heating Customers against total customers is defined as the Market Share in each forecast year. This forecast is used as an input into the Residential Basic Average Use Model.

Electric Vehicles

The Company's Electric Vehicle forecast represents cumulative energy additions from electric vehicle loads throughout the forecast period. This adjustment was based on

[6] Newfoundland Power's customer data as of August 2023 indicates that approximately 90% of new residential connections included electric heat. The remaining residential connections rely on other forms of heat including wood, or in the case of non-dwellings such as a shed, have no heating.

research conducted by Dunsky Energy Consulting ("Dunsky") quantifying the market potential of electric vehicles.

Dunsky provided an annual forecast of Electric Vehicle market growth. Newfoundland Power uses passenger light-duty vehicles as the basis for increased residential usage due to electric vehicles to produce an annual electrical energy need.[7]

Based on these annual electricity requirements, the Company produces a forecast for the cumulative impact of electric vehicles through 2028, reflecting that once EVs are adopted they continue to demand energy for the remainder of the forecast period. Newfoundland Power assumes, at least through the forecast period, that it will not need to consider the impact of EV retirements.

Conservation and Demand Management

Newfoundland Power forecasts future CDM impacts separately from the historical time series of observed CDM impacts shown in the Residential Basic Average Use Forecast. This adjustment methodology uses a forecast of incremental gross energy savings from takeCHARGE!, a joint CDM initiative between Newfoundland Power and Hydro. A summary of this data is provided in Table 4 below.

Table 4: Incremental Gross Energy Savings from Residential CDM Programs (kWh)

Program	2023F	2024F	2025F	2026F	2027F	2028F
Insulation	4,064,000	5,997,603	6,237,009	6,237,009	6,237,009	6,237,009
Thermostat	275,600	-	-	-	-	-
Instant	5,700,000	-	-	-	-	-
Benchmarking	(2,916,000)	(703,000)	(669,000)	-	-	-
HRV	398,000	308,370	323,760	323,760	323,760	323,760
Energy Savers Kit	2,500,000	2,645,640	2,811,140	2,811,140	2,811,140	2,811,140
Total Incremental Energy Savings	**10,021,600**	**8,248,613**	**8,702,909**	**9,371,909**	**9,371,909**	**9,371,909**

Newfoundland Power uses this data to produce a cumulative CDM forecast throughout the forecast period, directly reducing energy needs in each forecast year.

Heat Pumps

Newfoundland Power's heat pump impact forecast is based on the expected heat pump market growth and the typical energy savings associated with heat pumps supplementing electric heat. The market growth is determined using the market

[7] Dunsky estimates that usage associated with passenger light-duty vehicles is 4,500 kWh per year.

potential study produced by Dunsky and the results of the annual takeCHARGE! Marketing Survey. The typical energy savings is determined using internal data from customers who installed a heat pump.[8]

From the takeCHARGE! Marketing Survey, Newfoundland Power identified that heat pump households represented 20.2% of customers in 2019 and 27.41% of customers in 2022, representing an incremental market share increase of 7.21% over three years. They further determined a portion of heat pump installs in 2022 resulted from oil-to-electric heating conversions. As a result, the market share increase of heat pumps supplementing electric heating was estimated at 2.3% annually.

Newfoundland Power also used the Dunsky study to identify the market potential of heat pump adoption in its service area. A summary of the results of this study is provided in Table 5 below. Newfoundland Power selected the three-year average heat pump market shares to represent the estimated potential for heat pump adoption across various periods.

Table 5: Market Share of Residential Customers by Heat Pump Use

Heat Pump Use	2021	2022	2023	2024	2025	2026	2027	2028
Electric Baseboard to MSHP	1.300%	1.300%	1.200%	1.100%	0.700%	0.700%	0.700%	0.700%
Heat Pump Space Heating	0.015%	0.015%	0.015%	0.014%	0.012%	0.012%	0.012%	0.012%
Heat Pump Water Heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%
Total	**1.316%**	**1.316%**	**1.216%**	**1.115%**	**0.713%**	**0.713%**	**0.713%**	**0.713%**
			`23-`25 Average		1.0%	**`26-`28 Average**		0.7%

Newfoundland Power averaged the results of the takeCHARGE! Marketing Survey and Dunsky to produce an expected level of market share increase in heat pumps. This calculation is summarized in Table 6.

[8] These usage reductions were also compared to and found to be consistent with the results of Econoler's Heat Pump Load Study.

Table 6: Newfoundland Power Expected Heat Pump Market Share

Item	2020 - 2022	2023 - 2025	2026 - 2028
takeCHARGE! Historical Average	2.3%	2.3%	
Dunsky Potential Study		1.0%	0.7%
Average	**2.3%**	**1.7%**	**0.7%**

To determine the typical energy savings related to heat pumps, Newfoundland Power used customer usage data from a set of 255 customers. Newfoundland Power calculated the annual energy usage pre- and post-installation to produce an expected energy savings per heat pump, as summarized in Table 7.

Table 7: Expected Average Energy Savings from Heat Pumps (kWh)

Item	Group 1	Group 2	Total
Average Observed Savings	3,534	4,933	
Customers	184	71	255
Weighted Average Observed Savings	**2,550**	**1,373**	**3,923**

Based on these calculations, Newfoundland Power produced the calculations summarized in Table 8 below. Average heat pump installations in a given year were calculated as the product of the average heat pump market share and the number of customers observed in 2022. This product is multiplied by the expected energy savings per heat pump customer to produce an annual GWh adjustment to Newfoundland Power's forecast.

Table 8: Heat Pump Adjustment Summary

Item	2020 - 2022	2023 - 2025	2026 - 2028
Average Heat Pump Market Share	2.3%	1.7%	0.7%
2022 Customers	238,343	238,343	238,343
Average Heat Pump Installs	5,482	3,933	1,668
Average Savings per Customer (kWh)	3,923	3,923	3,923
Reductions in usage from heat pumps per year (GWh)	**22**	**15**	**7**

Oil to Electric Conversions

Newfoundland Power forecasted the impact of oil to electric conversions based on policy commitments from the Government of Newfoundland and Labrador. They provided a fiscal year forecast of customers that are expected to transition from oil to electric heating from 2023 through 2028. These conversions are then translated to calendar-year forecasts. Of these calendar year conversions, 94% were expected to reside in Newfoundland Power's service territory. Newfoundland Power assumes that each of these conversions will require an incremental 7,630 kWh to their annual energy needs, based on observed differences between the average electric and non-electric heating household in 2022. This process is summarized in Table 9.

Table 9: Oil-to-Electric Conversion Adjustment Summary

Incremental Annual Energy Requirements per Conversion (kWh)				7,630
Year	**FY Conversions**	**Calendar Conversions**	**NP Customers**	**Annual Energy (GWh)**
2023	2,382	1,787	1,700	13.0
2024	3,574	3,276	3,100	23.7
2025	2,981	3,129	2,900	22.1
2026	1,494	1,866	1,800	13.7
2027	0	374	400	3.1
2028	0	0	0	0.0

Reconciliations for Year-to-Date Actuals

Due to the September filing date of this forecast, Newfoundland Power had the opportunity to examine the accuracy of its forecast year-to-date. Newfoundland Power identified that actual sales in the first part of 2023 materialized higher than the forecasted 2023 sales.

To account for this underestimation, Newfoundland Power added a total of 105 GWh of energy demand to the Residential Basic energy forecast. They determined that this addition was expected to persist through the rest of the forecast period. In support of that determination, Newfoundland Power notes that residential energy sales in recent years have been positively impacted by record immigration, higher housing starts than those forecast by independent parties, and government electrification initiatives such as the oil-to-electric conversion program which were not reasonably foreseeable at that time.

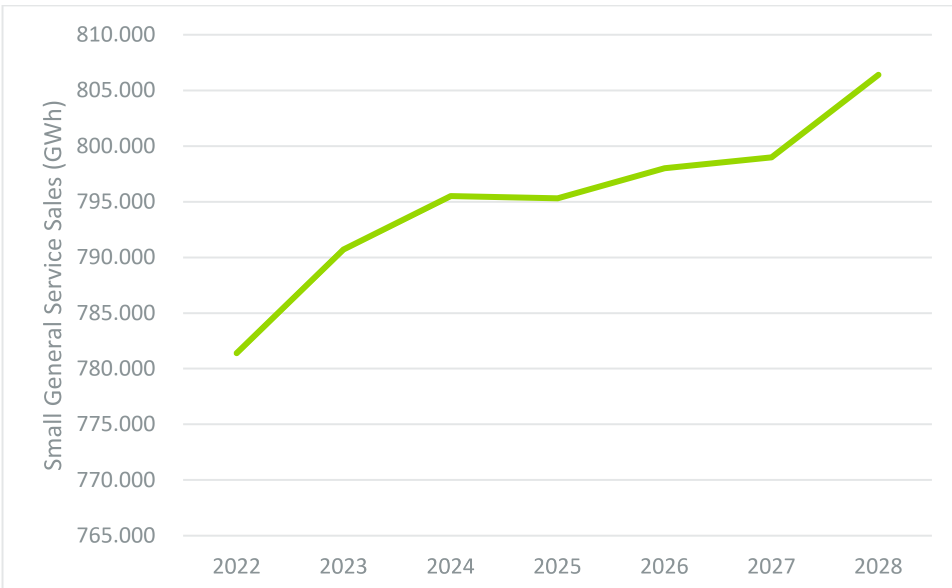
Final 2023 actual sales came in slightly below the adjusted forecast, but still higher than the forecast without the year-to-date adjustment.

D. General Service Sales

General Service Sales are calculated using a segmented approach that divides the category into Small General Service ("SGS"; Rate 2.1 for customers requiring 0-100 kW) and Large General Service ("LGS"; Rate 2.3 and 2.4 for customers 110 kVA and over).

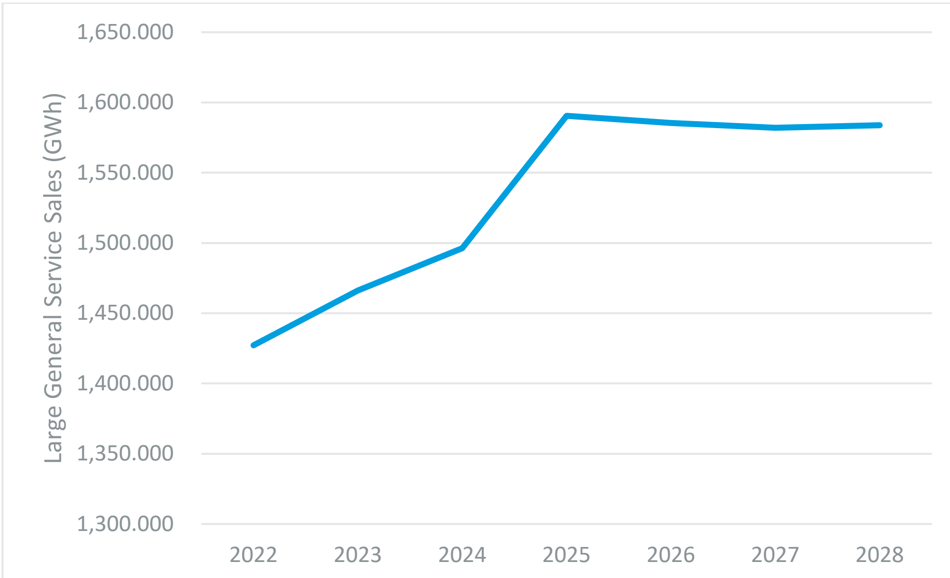
Small General Service sales are forecasted using an econometric model incorporating service sector Gross Domestic Product (“GDP”), electricity prices, customer count, and historical CDM. External adjustments are made, in a similar manner as Residential, for forecast CDM impacts and electric vehicle market growth impacts. Small General Service Sales (“SGSS”) were forecasted to increase modestly, as shown in Figure 4, growing at a CAGR of 0.53%.

Figure 4: Small General Service Sales Forecast (GWh)



Large General Service sales employ an informed opinion methodology with individual customer-based forecasting due to the relatively small number of customers. Newfoundland Power integrates specific customer information and applies adjustments for sector specific trends such as major conversion projects such as oil to electric heating system transitions as well as forecast CDM and electric vehicle market growth impacts. This class was forecasted to grow moderately, as shown in Figure 5, at a CAGR of 1.75%.

Figure 5: Large General Service Sales Forecast (GWh)



Small General Service Customers

Newfoundland Power's SGS Customer forecast uses a linear regression that is based on domestic customer growth projections. This approach leverages the relationship between residential development and the commercial services that support growing communities. As new residential customers are added to the system, Newfoundland Power forecasts a corresponding demand for supporting businesses and services. Table 10 summarizes the regression results.

Table 10: SGS Customers Regression Results

	Dependent Var:
Note: *** p < 0.001; ** p < 0.01; * p < 0.05.	GS 2.1 Custs
Residential Customers (t)	0.05912***
	(0.00113)
2022+ Dummy	267.996
	(209.766)
Constant	8708.386***
	(219.221)
Observations	40
R^2	0.9876
Adj R^2	0.987
Residual SE	200.5 (df = 37)
F Statistic	1478 (df = 2; 37)

The Residential Customers variable represents the domestic customer population growth. Newfoundland Power expects that the customer growth in the business/service sector is highly associated with the customer growth in the residential sector and looks to leverage this relationship in the model. The 2022+ dummy variable captures all years 2022 through the forecast period.

Small General Service Sales

Newfoundland Power's SGSS forecast uses an econometric approach that incorporates four key variables to project energy consumption/sales. The model uses service sector GDP as the primary economic driver, reflecting the correlation between commercial activity and electricity demand among small business customers. Average electricity prices are included to capture price elasticity effects on consumption behavior. The model also incorporates the forecasted number of SGS customers as an input variable, creating a direct linkage between customer growth projection (which is tied to domestic customer growth patterns) and energy sales forecasts. Additionally, external adjustments are made for forecast CDM impacts and electric vehicle market growth impacts. Table 11 and Equation 4 below summarize the regression specification and results of this model.

Equation 4: SGSS Model Specification

$$GS\_Sales_t = \beta_1 GDPSS_t + \beta_2 Price_t + \beta_3 CDM_t + \beta_4 Cust_t + \delta_1 D_{2022} + \delta_2 D_{2020} + \varepsilon_t$$

Table 11: SGSS Regression Results

	Dependent Var:
Note: ***** p < 0.001; ** p < 0.01; * p < 0.05.**	SGS Sales
SS GDP	6.920
	(4.32)
Electricity Price	-510.378
	(442.86)
2022+ dummy	38,665.748*
	(15,389.45)
CDM Impact	110,451.608***
	(15502.43)
2.1 Customers	45.594***
	(7.26)
2020 dummy	-18,811.097
	(12,894.83)
Constant	10,786,339.057
	(1,502,453.73)
Observations	38
R^2	0.98564455
Adj R^2	0.982866076
Residual SE	10420 (df = 31)
F Statistic	354.7 (df = 6; 31)

Independent Variables

Service Sector GDP is an economic variable that is derived from CBOC's Provincial Medium Term Economic Forecast from 2023. Newfoundland Power expects that GDP growth across the service sector requires more energy consumption to power increased economic activity, giving Service Sector GDP strong explanatory power for predicting small business energy sales.

Electricity Price represents the average price of electricity in the current year. This variable is indexed to 2002 to account for inflation.

Similar to the Domestic Average Usage model, the 2020 dummy variable captures COVID-19 impacts, the 2022+ dummy captures all years 2022 through the forecast period, and the CDM variable is the indexed energy CDM program impact.

External Adjustments

Similar to the Residential Sales model, Newfoundland Power applies adjustments to SGSS to account for CDM, electric vehicles, and reconciliations for year-to-date actuals. The process for these adjustments remains similar as well.

Large General Service Sales

The LGS Sales category covers rate 2.3, for customers 110-1000 kVA, and rate 2.4, for customers greater than 1000 kVA. Given the relatively small number of customers in the General Service category, LGS Sales are forecast on an individual customer basis rather than through econometric modeling. Newfoundland Power reaches out to customers tracked within this sub-class to understand any plans to increase their energy usage in the next three years. Newfoundland Power also monitors major project developments to identify any potential large loads during the forecast period.[9]

Newfoundland Power conducted direct customer surveys in 2023 of approximately 105 LGS customers representing 175 customer accounts across rates 2.3 and 2.4 to gather information on future load requirements. Survey respondents provided projections of annual energy usage through these surveys. Customer specific information was supplemented by data gathered from Newfoundland Power's regional operations, which provides local insights into customer activity and operational changes. Newfoundland Power also includes adjustments for electric vehicles, oil-to-electric heating conversion, energy conservation and year-to-date actuals in the LGS sales forecast.

This methodology allows Newfoundland Power the flexibility to capture case by case load changes such as facility expansions, industrial process modifications, or major conversions that would materially impact energy sales projections for this rate class.

External Adjustments

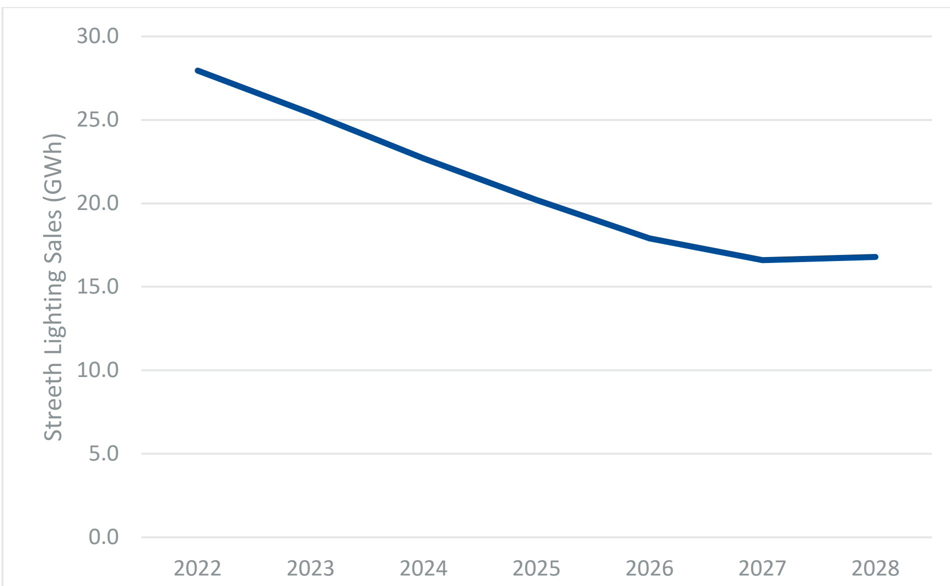
The LGS Sales model accounts for the impacts of electric vehicles using a similar methodology to that modelled for the Residential and SGS classes.

[9] For example, the Atlantic Economic Council's Major Project Inventory.

Street-Lighting Sales

Newfoundland Power’s Street and Area Lighting sales forecast employs an end-use forecasting methodology. With approximately 66,000 fixtures installed at the end of 2022, the forecast is determined by multiplying the projected quantity of fixtures by the electricity consumption associated with each fixture type and wattage. The methodology distinguishes between high-pressure sodium (“HPS”) and LED fixtures, recognizing the different energy consumption characteristics of each technology. A key component of the forecast is the incorporation of Newfoundland Power’s LED street lighting replacement plan, which involves replacing all HPS fixtures with more energy-efficient LED fixtures over a 6-year period. The Street Lighting sales forecast was forecast to decrease at a CAGR of ~8.14% from 2023 through 2027, when the project is expected to be complete. The forecast is shown in Figure 6 below.

Figure 6: Street Lighting Sales Forecast (GWh)



E. Produced & Purchased Energy

Total produced, purchased and wheeled energy is calculated by adding company use, system losses, and wheeled energy to the sum of all customer sales categories (Domestic, General Service, and Street and Area Lighting). Company use represents electricity consumed in Newfoundland Power’s own facilities for service delivery, and system losses accounting for energy lost during transmission and distribution, while wheeled energy assumptions are provided by Hydro. Purchased energy is then determined by subtracting normal hydroelectric production from total produced and purchased energy, with normal production adjusted annually to reflect plant availability and any modifications that may impact generation output.

Company Use

Company use reflects energy usage from Newfoundland Power facilities including office buildings. The forecast is based on historical energy usage from each of these sites and held constant throughout the forecast period.

Losses

System losses are assumed to be 4.8% of total produced and purchased energy throughout the forecast period. This assumption is based on average system losses in 2022.

Wheeled Energy

Wheeled energy serves customers of Hydro outside of Newfoundland Power's service territory. NLH provides a three-year forecast of monthly wheeled energy volumes which NLH directly incorporates into its produced and purchased energy forecast.

F. Peak Demand Forecast

Newfoundland Power forecasts its native peak demand to estimate expected purchased power costs from Hydro throughout the forecast period. The Company employs a load factor-based methodology, where load factor represents the ratio of average demand to peak demand on the electrical system.

The native peak calculation uses a five-year average of normalized annual load factors, which is then applied to total produced and purchased power to determine the expected peak demand. The five-year average load factor from 2018 to 2022 was 49.35%.[10]

Purchased power demand is calculated by subtracting both the generation credit and curtailable credit from the native peak. The generation credit accounts for Newfoundland Power's own generating capacity less an allowance for system reserve, while the curtailable credit reflects load that can be curtailed by customers participating in the Company's curtailable service option program. These credits adjust the native

[10] This excluded 2020, which was abnormally high due to the effects of the COVID-19 pandemic.

peak to determine Hydro's billing demand, which forms the basis for purchased power cost calculations under Hydro's utility rate structure.

G. Additional Forecast Assumptions

Price and Price Elasticity

Newfoundland Power incorporates price elasticity effects into its forecasting models through the inclusion of price variables, capturing the customer response to changes in electricity price.[11] As such, the coefficients attached to the marginal price and lagged marginal price terms in the residential regression model establish the price elasticity of residential energy sales while the coefficient attached to the average electricity price in the SGS regression establishes the price elasticity of SGS energy sales.

To provide another measure of price elasticity, Newfoundland Power applies a 1% electricity rate increase to the CED Forecast models and observes the resulting change in electricity consumption. The price elasticity analysis from the 2025/2026 GRA indicates that customer price response is relatively inelastic, with a 1% increase in electricity prices resulting in a 0.30% decrease in Residential Sales and a 0.19% decrease in total sales. Using 2022 customer data as a reference, the residential price elasticity implies that a $1 increase in the Marginal Price Index of electricity results in an approximate 37 kWh decrease in residential average usage per year.

Electricity price forecasts are based on internal analysis and information from Hydro. In the 2025/2026 GRA, the forecast under existing rates includes a 6.9% increase on July 1, 2023, roughly 9% on July 1, 2024, and 2.25% increase on July 1st in both 2025 and 2026. Under proposed rates, an additional 5.5% increase was included effective July 1, 2025 to account for the additional customer rate increase requested in the 2025/2026 GRA.

The Company recognizes that price responsiveness varies by timeframe and rate category, and that changes in competing fuel prices (particularly heating oil) can impact electricity's market share in the space heating sector. Historically, however, heating fuel switching from electric to oil has been rare and costly, hence not likely to be influenced by price elasticity.

[11] Price elasticity is defined as the change in quantity demanded divided by the change in price.

H. Model Performance

System Energy Forecast Performance

Newfoundland Power's total energy sales forecast shows differences ranging from 1.64% (96 GWh) to -1.10% (-64 GWh) from 2013 to 2022. The average forecast accuracy during this period was -0.25%. This includes the period during which the COVID-19 pandemic occurred which created additional forecasting challenges and uncertainty. A summary table of the last five years' forecasts versus weather adjusted sales is provided in Table 12 below.

Table 12: Forecast Energy Sales vs Weather Adjusted Actuals (GWh)[12]

Year	Forecast Sales	Weather Adjusted Actuals	% Error
2019	5,882.9	5,846.6	-0.62%
2020	5,793.0	5,729.0	-1.10%
2021	5,719.5	5,715.0	-0.08%
2022	5,699.3	5,784.5	1.49%
2023	5,832.4	5,927.9	1.64%

Residential Average Usage Model Performance

The Residential Average Usage model forecast errors ranged from -0.54% (-83 kWh) to 2.40% (351 kWh) from 2019 to 2023. The model shows mixed performance across the five-year period. The error rate in 2022 represented the largest deviation where actual usage exceeded the forecast by 2.40% (351 kWh). The model achieved high accuracy in 2019 and 2021 with errors of 0.35% and 0.20%, respectively. Table 13 summarizes the last five years of forecasts vs actuals for the domestic model (measured in kWh).

Table 13: Residential Sales vs Actuals (kWh)[13]

Year	Forecast Sales	Weather Adjusted Actuals	% Error
2019	15,236	15,289	0.35%
2020	14,971	15,172	1.34%
2021	14,796	14,825	0.20%
2022	14,618	14,969	2.40%
2023	15,347	15,264	-0.54%

[12] 2025/2026 General Rate Application, Response to PUB-NP-089. Errors are calculated as "(Actual – Forecast)/Forecast"

[13] 2025/2026 General Rate Application, Response to PUB-NP-087

Small General Service Sales Model Performance

The SGSS model forecast errors ranged from -0.05% to -6.12% from 2019 - 2023. However, the -6.12% error occurred during the 2020 COVID-19 pandemic year and should be treated as an outlier. Outside of the 2020 outlier, the model shows high performance accuracy in recent years. Table 14 below summarizes the last five years of forecasts vs actuals for the SGSS model (measured in GWh).

Table 14: SGSS Model Forecast vs Actuals (GWh)[14]

Year	Forecast Sales	Weather Adjusted Actuals	% Error
2019	803.5	799.3	-0.52%
2020	801.1	752.1	-6.12%
2021	769.7	768.7	-0.13%
2022	784.5	784.1	-0.05%
2023	791.5	790.2	-0.16%

IV. DAYMARK ANALYSIS

This section presents Daymark's independent review of Newfoundland Power's load forecast. Load forecasting serves as a critical foundation for utility resource planning, rate design, cost recovery, and system operations. An accurate and methodologically sound forecast allows utilities to make informed decisions while minimizing costs and risks to ratepayers.

Daymark was retained to conduct a comprehensive technical review of Newfoundland Power's utility load forecasting methodologies to assess model specification, performance, and underlying assumptions. This analysis evaluates the statistical validity of Newfoundland Power's econometric models, examines forecast accuracy at both the system and customer class levels, and reviews the appropriateness of external adjustments applied to baseline forecasts. The following sections present Daymark's findings organized by customer class and forecasting component, with particular attention to model specifications, validation of key assumptions, and opportunities for improving model fit and reliability.

[14] 2025/2026 General Rate Application, Response to PUB-NP-088

Description of Daymark Review Approach

Daymark's review of Newfoundland Power's CED Forecasting methodologies employed a systematic framework to assess model validity, performance, and reliability. The review included an analysis of forecast error, model performance, and the validity of underlying assumptions.

For econometric models, Daymark replicated each model in the R statistical programming environment using data and model specifications provided by the Company.[15] Once replicated, Daymark conducted a suite of statistical diagnostic tests to evaluate the robustness of each regression, including tests for autocorrelation, heteroskedasticity, and multicollinearity. Beyond diagnostic testing, Daymark evaluated model specification decisions, such as the appropriateness of functional forms and the inclusion or exclusion of specific variables. Alternative specifications were tested where appropriate to assess robustness and identify potential improvements.

For non-econometric models, Daymark analyzed the validity of underlying assumptions, testing these assumptions against independent data. Both the original models and any alternative specifications were examined on the basis of model fit, with the examination of error levels used to identify the cause of any bias in the forecast.

Following this process, Daymark drew conclusions regarding each model's statistical validity and forecast reliability, identifying areas for potential enhancement.

Total Energy Sales

In total, the Company's CED Forecast demonstrated an acceptable level of error of 1% or less, as demonstrated in Table 15. This error rate indicates a slight overestimation in the Company's forecast for the years 2023 and 2024.

[15] R allows for rapid testing of model performance and alternative specifications along with additional statistical testing. This functionality is present in Excel, but requires significantly more time to accomplish. As such, Daymark elected to transfer the models to a more modern forecasting platform.

Table 15: Total Energy Sales Error (GWh)

Sales	2023	2024	2025
Forecast[16]	5,949	5,981	6,018
Actuals[17]	5,928	5,926	
Error	(21)	(55)	
Error (%)	(0.35%)	(0.92%)	

Residential Sales

The Company's Residential Sales forecast performs well with a negligible error rate, as demonstrated in Table 16.

Table 16: Residential Sales Error (GWh)

Sales	2023	2024	2025
Forecast[18]	3,667	3,667	3,615
Actuals[19]	3,656	3,656	
Error	(11)	(11)	
Error (%)	(0.30%)	(0.30%)	

When excluding external adjustments made to account for observed data in 2023, the error rate increases and changes direction to show a slight underestimation, as shown in Table 17. While this error rate remains within acceptable levels, it highlights that the Company's base models do not capture all of the sales in the Residential class. If this underestimation persists into the future or is persistent in historical forecast, Newfoundland Power should consider sources of underestimation bias in the econometric models which may not be reasonably captured through external adjustments.

[16] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[17] CED Forecast Summary, April 18, 2025

[18] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[19] CED Forecast Summary, April 18, 2025

Table 17: Residential Sales Error, Excluding YTD Adjustments[20] (GWh)

Sales	2023	2024	2025
Forecast[21]	3,561	3,572	3,525
Actuals	3,656	3,656	
Error	95	84	
Error (%)	2.67%	2.35%	

Residential Customer

Newfoundland Power's Residential Customer forecast is primarily based on an external forecast of housing construction, informing 3-year future growth based on historical average net customer growth relative to housing construction. This forecast performs well with a negligible error rate, as demonstrated in Table 18. Given the performance of this model and its basis on an external forecast, Daymark does not deem further refinement of this model is a high priority at this time.

Table 18: Residential Customers Error (customers)

Customers	2023	2024	2025
Forecast[22]	239,605	240,595	241,461
Actuals[23]	239,748	241,416	
Error	143	821	
Error (%)	0.06%	0.34%	

Residential Average Usage

The Residential Average Use forecast is based on an econometric model, showing a reasonable level of error, approximately 2% or lower, excluding external adjustments, as shown in Table 19 below. The error rate suggests a slight underestimation of load across the forecast period.

[20] YTD Adjustment refers to external adjustments applied in 2023 to account for observed data. These adjustments are not intended to capture any specifically identified trends, rather accounting for the most recent data.

[21] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[22] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[23] CED Forecast Summary, April 18, 2025

Table 19: Unadjusted Residential Average Use Error (kWh/customer)

Avg. Use	2023	2024	2025
Forecast	14,956	14,931	14,681
Actuals	15,264	15,204	
Error	308	273	
Error (%)	2.06%	1.83%	

To examine the performance of this model, Daymark replicated Newfoundland Power's Residential Average Usage model with regression results summarized in Table 3.

The model demonstrates strong fit with an adjusted R^2 of .980 and a statistically significant F-statistic. Daymark performed multiple additional tests to further examine how the model performs.

Table 20: Statistical Performance of Residential Average Usage Model[24]

Test	Statistic	P-Value	Result
Durbin Watson	.636	< .001	Model exhibits positive autocorrelation
Breusch Pagan	6.274	.508	No heteroskedasticity present in the model
Augmented Dickey Fuller	Varies by Variable	Varies by Variable	Average Usage, CDM index, Income/Customer are all non-stationary while Market Share and Marginal Prices are stationary.
Variance Inflation Factor	All < 5.65	N/A	No severe multicollinearity issues are present in the Model

Table 20 summarizes the baseline statistical tests conducted on Newfoundland Power's Residential Average Usage Model. Statistical tests were selected based on their importance to validating the baseline assumptions for linear regression and forecasting. While it is beyond the scope of this study to discuss the mathematical specifics of how these tests operate, a baseline understanding of what each test looks for is required:

[24] Each of these tests provide additional information on the performance of the model with potential pathways for improvement. While test results that fall outside preferred ranges may indicate deficiencies in the performance of the model, they do not necessarily suggest that the model is unreasonable. The ultimate test of reasonableness is the model's ability to forecast accurately over time.

- **Durbin Watson:** Tests for autocorrelation (serial correlation) in regression residuals. If present autocorrelation indicates that errors are correlated over time, violating ordinary least squares ("OLS") assumptions and making standard errors unreliable, which leads to inefficient forecasts and invalid confidence intervals. This statistic ranges from 0 to 4 with values around 2 indicating no or insignificant autocorrelation. Values substantially below 1 denote positive autocorrelation while values above 3 indicate negative autocorrelation.

- **Breusch Pagan:** Tests for heteroskedasticity (non-constant variance) in residuals. If present, heteroskedasticity means the error variance systematically changes across observations, rendering standard errors and hypothesis tests unreliable and producing inaccurate forecast intervals.

- **Augmented Dickey Fuller ("ADF"):** Tests for stationarity by detecting unit roots in time series data. A negative result indicates non-stationarity in the data which can cause spurious regressions, trending or drifting forecasts, and fundamentally unreliable model inferences. Stationarity refers to the assumptions that the key statistical properties of a time series (mean, variance, and autocorrelation) remain constant over time. Without stationarity, a model must account for any non-stationary effects.

- **Variance Inflation Factor ("VIF"):** Measures multicollinearity among the independent variables in regression. If present, independent variables are highly correlated which can create unstable coefficient estimates. For forecasting, high multicollinearity is less problematic than for inference but can reduce out of sample performance.

The Durbin Watson test reveals a potential area of improvement with the Residential Average Usage model. With a statistic of .636 and p-value <.001, the test indicates that there is positive autocorrelation in the model's residuals, suggesting that rising Residential Average Use in one period is expected to generally increase in the following period.

The presence of autocorrelation tells us that the residuals are dependent on each other to some extent. This means that the model's standard errors may be unreliable and are likely understated, which produces confidence intervals that are narrower than they otherwise should be because the model is not capturing systematic patterns in the errors. This suggests the model may be mis-specified, potentially missing important variables or lagged effects that should be addressed through model restructuring, such as incorporating lagged dependent variables, or using an auto-regressive integrated moving average model with exogenous inputs ("ARIMAX") specification.

The Breusch Pagan test provided a test statistic of 6.274 and a p-value of .508. The results indicate that the model does not exhibit heteroskedasticity. This finding supports the validity of the model's inference. The absence of heteroskedasticity means that standard errors and hypothesis tests remain reliable, and forecast intervals are appropriately calibrated with respect to variance. This result suggests that we can be confident the model appropriately handles variance across the ranges of predictions.

The ADF test was conducted on each variable in the regression to formally assess stationarity. The ADF test checks for the presence of a unit root (trend), which would indicate non-stationarity. To understand this issue, consider "stationary" data as stable and predictable over time; it fluctuates around a consistent average and does not have a long term upward or downward drift. "Non-stationary" data, however, tends to wander and trend over time without settling around a stable level, much like stock prices that generally rise over decades or population that steadily grows.

The test shows that three variables (Average Usage, CDM Index, and Income/Customer) are non-stationary, while Market Share and Marginal Prices are stationary. A statistical model using non-stationary variables could produce misleading results. For example, a statistical model might show a strong relationship between annual electricity consumption in a city and the number of restaurants that are opened in a given year (assuming growth in restaurant count), but this does not imply that higher electricity consumption causes restaurant growth. These variables are likely trending upward due to the progression of the broader economy.

To address this issue, Newfoundland Power should transform the variables to make them stationary, such as looking at year-over-year changes rather than absolute levels. Alternatively, Newfoundland Power could use more sophisticated modeling techniques such as an ARIMAX specification designed specifically for data with these characteristics.

The VIF provided values below 5.65 for all variables, within acceptable thresholds (commonly set at VIF <5 or < 10). As such, no severe multicollinearity is present among the independent variables. This implies coefficient estimates are stable, not excessively sensitive to small changes in the data, and individual predictors can be interpreted with reasonable confidence. While multicollinearity is less problematic for forecasting than for inference, the low VIF values suggest good out-of-sample performance potential and indicate that the independent variables provide relatively unique information to the model.

To address the non-stationarity and autocorrelation issues present in the model, Daymark conducted multiple different sensitivities. These sensitivities not only look to address the underlying issues present in the model, but also look to test the inclusion and exclusion of different variables as well as variable transformations such as logs and lags. Table 21 below summarizes the different sensitivities Daymark tested.

Table 21: Summary of Residential Average Usage Model Sensitivities[25]

Sensitivity	Goal
Log-Log	Improve model fit
1st Lag Inclusion	Address autocorrelation
1st and 2nd Lag Inclusion	Address autocorrelation
1st 2nd and 3rd Lag Inclusion	Address autocorrelation
ARIMAX Model	Address both autocorrelation and non-stationarity
Exclusion of specific variables	Improve model efficiency and reduce potential overfitting

The log-log specification is a transformation of the base model from absolute values to a natural logarithm basis for all continuous variables. The CDM Index and dummy variables (2022+, 2020) remain in their original form as they are already index values or binary indicators. This transformation changes the interpretation of coefficients from absolute changes to percentage changes.

The first lag inclusion specification builds upon the log-log transformation but introduces an additional component by including the first lag of the natural log transformed dependent variable as an independent variable. The inclusion of the lagged dependent variable as an independent variable fundamentally changes the model's structure from a static regression to an autoregressive distributed lag specification where current usage is partially explained by previous usage. The intuition is to capture inertia in residential

[25] Further summary statistics and residuals are provided in Appendix A, Sections I.B through I.G

electricity consumption patterns that the base model cannot address and look to address the autocorrelation present in the base model.

The second and third lag inclusion sensitivities extend the first lag sensitivity by sequentially adding additional lags of the dependent variable. Each additional lag increases the model's ability to capture temporal dynamics and longer memory in the consumption process. However, this comes at the cost of additional parameters and the potential for overfitting. The structure otherwise mirrors the first lag specification.

The ARIMAX specification looks to explicitly account for temporal dependencies through an integrated autoregressive moving average structure with exogenous regressors. The model uses the same external variables as the base specification. The ARIMA function in R automatically selects the optimal number of autoregressive and moving average terms that maximize the goodness of fit.

Different sensitivities were conducted to look at the exclusion of various variables, including the income/customer variable which is not found to be significant in the base model. The goal is to achieve a more parsimonious specification that focuses exclusively on variables demonstrating meaningful statistical relationships with average usage, attempting to improve model efficiency and out of sample forecast performance by reducing noise from non-contributing predictors.

Table 22 below summarizes the error metrics of the Newfoundland Power base model against the various sensitivities.

Table 22: Sensitivity Performance Metrics[26]

Error Metric	Newfoundland Power Base	1st lag	1st & 2nd lag	1st, 2nd, & 3rd lag	ARIMAX	Significant Variables Only
MAPE	.79%	.69%	.46%	.41%	.59%	.80%
RMSE	157.7	135.2	90.86	80.03	117.1	159.28

The results presented in Table 22 reveal marginal differences in accuracy across model specifications, indicating that the Newfoundland Power Base model performs reasonably well. The inclusion of lagged dependent variables as well as the ARIMAX specification improves model performance slightly. While the progressive improvement in error

[26] Daymark did not discount marginal price coefficients in any of the models.

metrics as additional lags are included warrants further exploration, it is important to note that there is risk of overfitting to historical data. Daymark recommends that Newfoundland Power maintain its existing Base model but also continue to test it against the above models, as well as any alternate specifications, in a forecast environment. Newfoundland Power could adopt a new model if it were proven to be more accurate.

The ARIMAX framework offers a certain structural advantage that may make it better suited for forecasting applications compared to standard OLS regression. The key strength of the ARIMAX specification lies in its explicit treatment of time series properties through its integrated framework. The model structure is fundamentally designed for the temporal dependencies inherent in time series data. ARIMAX treats the time series structure as a core feature of the model, rather than something that needs to be accounted or corrected in a standard OLS model. Daymark recommends that the ARIMAX framework be tested thoroughly from Newfoundland Power to assess robustness compared to the base specification.

Visual inspection of the forecast comparison chart in Figure 7 below provides valuable insights into model behavior.

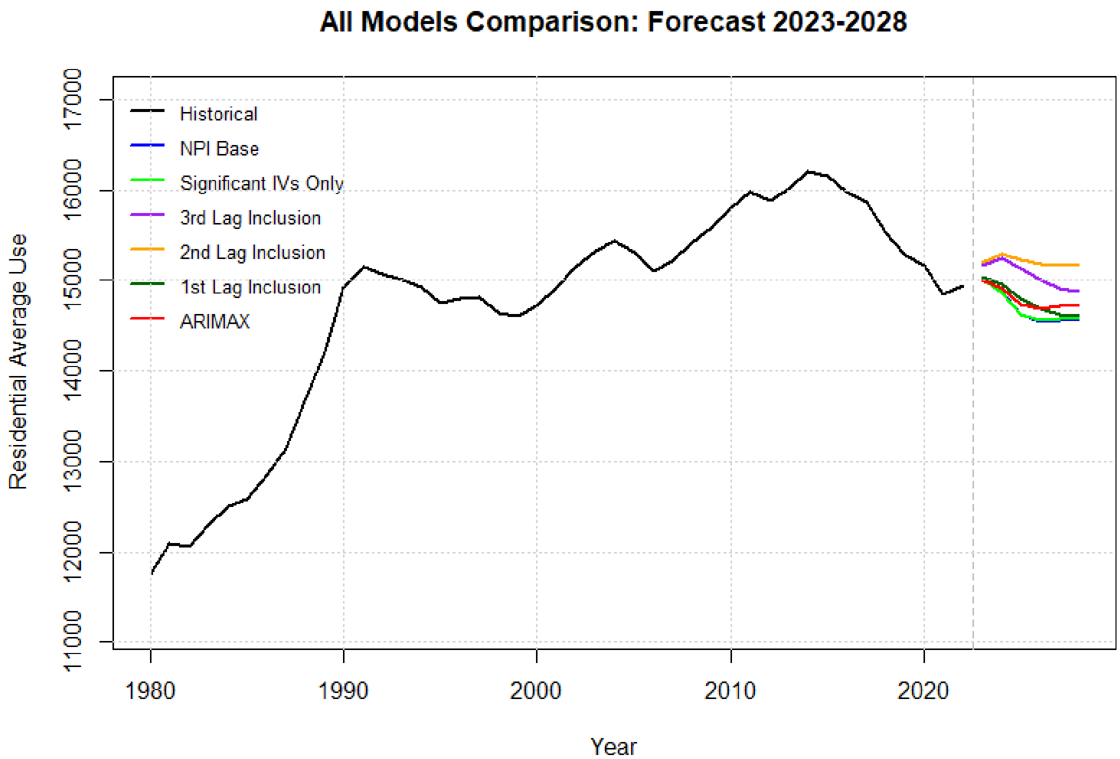


Figure 7: Average Usage Forecast Visualization

Most model specifications demonstrate relatively similar forecast trajectories through 2028. The general alignment across multiple different specifications suggests an important point. The base model captures the fundamental drivers of residential consumption reasonably well, as alternative specifications do not produce materially divergent long-term forecasts. As stated earlier, it is worth investigating to what extent temporal dependencies influence average usage. While the 2nd and 3rd lag inclusion sensitivities produced the lowest error metrics in Table 22, the forecast visualization supports earlier concerns about potential overfitting as these two sensitivities visually diverge from the rest. The addition of multiple lagged dependent variables increases model complexity, with each lag adding another parameter that must be estimated from a limited yearly data set using up an additional degree of freedom. The fear is that with the addition of too many parameters, the model starts capturing random noise rather than the true underlying relationships.

External Adjustments

A summary of all external adjustments to the Residential Sales model is provided Table 23 below. These adjustments represent ~2% to ~3% of the unadjusted Residential energy sales projected in each forecast year.

Table 23: Summary of Residential Sales External Adjustments (Cumulative GWh/year)

Year	YTD Adjustment	Oil to Electric Conversion	Heat Pumps	Electric Vehicles	CDM	Total
2023	105.0	13.0	(15.0)	0.6	(10.0)	**93.6**
2024	105.0	36.7	(30.0)	2.3	(18.2)	**95.8**
2025	105.0	58.8	(45.0)	4.7	(26.9)	**96.6**
2026	105.0	72.5	(52.0)	8.0	(36.3)	**97.2**
2027	105.0	75.6	(59.0)	12.7	(45.7)	**88.6**
2028	105.0	75.6	(66.0)	19.7	(55.1)	**79.2**

Adjusted for the projected Residential customer counts in each year, these adjustments are not significant, as shown in Table 24.

Table 24: Summary of Residential Sales External Adjustments (Cumulative kWh/customer-year)

Year	YTD Adjustment	Oil to Electric Conversion	Heat Pumps	Electric Vehicles	CDM	Total
2023	439.6	54.4	(62.8)	2.3	(41.9)	**391.7**
2024	437.8	153.0	(125.1)	9.4	(75.9)	**399.2**
2025	436.2	244.3	(186.9)	19.5	(111.8)	**401.3**
2026	434.9	300.3	(215.4)	33.1	(150.3)	**402.5**
2027	433.8	312.3	(243.7)	52.6	(188.8)	**366.1**
2028	433.2	311.9	(272.3)	81.2	(227.4)	**326.7**

Notably, the load reducing impacts of the Heat Pump and CDM adjustments are entirely cancelled out by the load increasing “YTD Adjustments” performed by the Company, until 2028. This suggests the presence of a possible underestimation bias in the models prior to external adjustments.

Electric Vehicles

The electric vehicle adjustment for the residential class appears reasonable based on the underlying assumptions. These assumptions are discussed in greater detail below.

Newfoundland Power uses an external forecast for EV growth paired with an external estimate from Dunsky of 4,500 kWh/year in electrical demand per vehicle.[27] Analysis

[27] Based on light-duty passenger vehicles assumptions provided by Dunsky.

from Argonne National Labs in 2019 found that the average battery electric vehicle consumed ~3,770 kWh per year.[28] While this average usage is lower than the value assumed by Newfoundland Power, colder weather can significantly impact the ability for a battery to hold charge, requiring greater usage per vehicle over the course of a year. Some estimates suggest that cold weather at sub-freezing temperatures can result in range loss up to 69%.[29] Given these impacts, the 4,500 kWh/year is reasonable and potentially conservative when accounting for cold weather impacts. Newfoundland Power should further qualify this assumption in the future.

For the vehicle forecast, the Company selects the “low” scenario in Dunsky’s EV forecast to inform future growth. This is likely a reasonable selection, considering that the province reflects the second lowest EV adoption rate in Canada where data is available.[30] However, further discussion of the methodology underlying Dunsky’s forecast is necessary in Newfoundland Power’s documentation to further analyze the reasonableness of this forecast.

However, given the small magnitude of these adjustments relative to the Residential class and the overall system (less than 1% of Residential sales throughout the forecast period), further analysis of this adjustment is not an immediate priority. Newfoundland Power should continue to monitor and refine this adjustment.

Conservation and Demand Management

The CDM forecast, represented as the cumulative impact of CDM programs on an energy basis, is informed by takeCHARGE!, a joint initiative with Newfoundland Hydro. This entity provides the underlying CDM forecast which is then incorporated into the Residential Forecast. This data is summarized in Table 25.

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[28] Argonne National Labs, *Assessment of Light-duty Plug-in Electric Vehicles in the United States, 2010-2019* - https://tedb.ornl.gov/wp-content/uploads/2021/01/ANL_Assessment_of_LD_PEV_2010-2019.pdf#:~:text=2.3%20ELECTRICITY%20CONSUMPTION%20BY%20PEVs%20In%202019%2C,average%20BEV%20consumed%203%2C770%20kWh%20of%20electricity.

[29] Esparza, Eliseo, Dana Truffer-Moudra, and Cabell Hodge. 2025. Electric Vehicle and Charging Infrastructure Assessment in Cold-Weather Climates: A Case Study of Fairbanks, Alaska. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5400- 92113. https://www.nrel.gov/docs/fy25osti/92113.pdf.

[30] Government of Canada, *Zero-emission Vehicle Dashboard,* Light-Duty ZEV Market Share - https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/zev-council-dashboard#2024-census

Table 25: CDM Impact on Residential Sales (GWh)

Year	Annual CDM	Cumulative CDM
2023	(10.0)	(10.0)
2024	(8.2)	(18.2)
2025	(8.7)	(26.9)
2026	(9.4)	(36.3)
2027	(9.4)	(45.7)
2028	(9.4)	(55.1)
CAGR	**-1.03%**	**32.90%**

The 2023 CDM report shows that expected annual energy savings from CDM totaled approximately 27,132 MWh of savings in the same year. However, Newfoundland Power's forecast only assumed savings of 10 GWh (10,000 MWh), as shown in Table 25.

This is due to exclusion of energy savings from the Benchmarking program from the forecast years since they are already embedded in Newfoundland Power's residential average usage and there are no incremental benchmarking initiatives in the forecast years. This is unlike other programs such as the Insulation and Air Sealing Program, HRV Program, and Energy Savers Kit Program which will continue to provide incremental customer energy savings over the forecast period.

Heat Pumps

The heat pump adjustment is based on the market potential study performed by Dunsky, the takeCHARGE! Marketing Survey and customer pre- and post-installation data.

The Company's assumption of 3,923 kWh in savings is reasonable since it is based on actual Newfoundland Power customers that have switched to heat pumps. Certain estimates find that heat pumps that are designed for cold-weather operation could achieve 3,000 kWh in savings relative to electric resistance heating and 6,200 kWh compared to oil systems when placed in the Northeast and Mid-Atlantic regions of the United States.[31] While Newfoundland presents colder weather than is typical for the target geography of this study, the region has historically used a mixture of oil and electric resistance heating, explaining why average savings may exceed 3,000 kWh.

Ultimately, Newfoundland Power should continue to refine the heat pump adjustment model, particularly the market penetration assumptions. In the context of

[31] U.S. Department of Energy, *Air-Source Heat Pumps* - https://www.energy.gov/energysaver/air-source-heat-pumps

underestimation bias present in the forecast, placing greater scrutiny on load reducing forecast adjustments is prudent.

Oil to Electric Conversions

Oil to electric conversions are based on provincial policy commitments. The methodology for constructing this adjustment is reasonable. Newfoundland Power should continue to monitor and validate this model, particularly tracking the rate at which conversions materialize relative to policy commitments.

Reconciliation for Actuals

Based on materialized load in the middle of 2023, Newfoundland Power added 105 GWh of demand to the Residential sales forecast in every year of the forecast. The need for this upward reconciliation illustrates the potential underestimation bias present in the econometric model, though of a small magnitude.

Small General Service Sales

The SGSS forecast performs reasonably well, exhibiting an error rate of 1.4% or lower, as demonstrated in Table 26. There is a slight overestimation in this model.

Table 26: Small General Service Sales Error (GWh)

Sales	2023	2024	2025
Forecast[32]	791	796	795
Actuals[33]	789	785	
Error	(2)	(9)	
Error (%)	(0.3%)	(1.4%)	

Small General Service Customer

The Small General Service Customer forecast is based on a linear regression based on Residential Customer growth along with a dummy for 2022 and beyond. The model performs reasonably well with an error rate less than 1% as shown in Table 27.

[32] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[33] CED Forecast Summary, April 18, 2025

Table 27: Small General Service Customer Error (customers)

Customers	2023	2024	2025
Forecast[34]	23,243	23,352	23,453
Actuals[35]	23,168	23,218	
Error	(75)	(134)	
Error (%)	-0.3%	-0.6%	

The model exhibits a reasonable R^2 value of 0.9876 with a mean absolute percentage error of less than 1%. Given the performance of this model, Daymark does not deem further modification of this model necessary at this time.

Notably, the results of this forecast are used as inputs into the SGSS model. Generally, using the results of an internal econometric forecast as an input into another forecasting model is not a common utility practice due to the potential for compounding errors and biased coefficients. Newfoundland Power should consider the need to use a Small General Service Customer model if it intends to use a broader sales forecast model.

Small General Service Sales

Similar to how Daymark replicated the Newfoundland Power residential average usage model in R, the SGSS model was also replicated. Daymark conducted the same suite of statistical tests on the SGSS model to gain a baseline understanding of variable and model specification. Table 28 below summarizes the statistical tests conducted on the SGSS model and the results.

[34] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[35] CED Forecast Summary, April 18, 2025

Table 28: Statistical Tests Conducted on Small General Service Sales Model

Test	Statistic	P-Value	Result
Durbin Watson	.550	< .001	Model suffers from positive autocorrelation
Breusch Pagan	9.97	.1261	No Heteroskedasticity present in the model
Augmented Dickey Fuller	Varies by Variable	Varies by Variable	General Service Sales, GDP-SS, CDM Index, and 2.1 customers all non-stationary while 2002 prices are stationary.
Variance Inflation Factor	Varies by Variable	N/A	GDP-SS and 2.1 Customers are highly correlated with other predictors in the model. VIF of 35.48 and 48.59 respectively

Table 28 summarizes the statistical tests conducted on the SGSS model. The diagnostic testing revealed a couple of different concerns requiring further analysis. The Durbin Watson test indicated positive autocorrelation in the residuals, similar to issues identified in the residential class. The Breusch Pagan test showed no heteroskedasticity, confirming constant error variance. The ADF tests revealed missed stationary properties within the data, with General Service Sales, GDP-SS, 2.1 Customers, and CDM Index all testing as non-stationary while 2002 prices were stationary. The VIF test identified multicollinearity, with GDP-SS and 2.1 Customers showing VIF values of 25.47 and 48.49 respectively, well above the accepted threshold of 5.

To address these concerns, Daymark conducted multiple model sensitivities summarized in Table 29 below.

Table 29: Model Sensitivities

Sensitivity	Goal
Exclusion of GDP-SS	Improve model fit
Exclusion of Rate 2.1 Customers	Address autocorrelation
1st Lag Inclusion	Address autocorrelation
1st and 2nd Lag Inclusion	Address autocorrelation
ARIMAX Model	Address both autocorrelation and non-stationarity

The first two sensitivities examined the exclusion of each highly multicollinear variable individually, first removing GDP-SS, then removing the independent variable for Rate 2.1 Customers to assess whether elimination one of the correlated predictors would improve model stability and performance. While multicollinearity is often cited as less problematic for forecasting than for statistical inference, it can still pose challenges for out of sample prediction. When two variables are highly correlated, they provide largely redundant information, making it difficult for the model to distinguish their individual effects. This can create unstable coefficient estimates that can vary with small changes in the data. By testing specifications that exclude one of the correlated variables, Daymark assessed whether a more parsimonious model might provide more robust forecasts.

Additional sensitivities incorporated lagged dependent variables at various levels to address the autocorrelation identified in the base model. Similar to the Residential Average Usage model, including lagged values of General Service Sales as an independent variable transforms the static OLS regression into an autoregressive distributed lag specification that can capture temporal patterns in the dependent variable. Finally, an ARIMAX model specification was tested to simultaneously address both the autocorrelation and non-stationarity concerns identified in the diagnostic testing. As discussed in the sections above, the ARIMAX framework offers a time series structure explicitly designed to handle these issues. The ARIMAX specification provides an alternative modeling approach that may better suit the temporal structure of utility sales data for longer-term forecasting applications.

Table 30 below summarizes how each sensitivity performs in terms of model fit compared to the Base model.

Table 30: Sensitivity Performance Metrics

Error Metric	Newfoundland Power Base	GDP Exclusion	2.1 Customer Exclusion	1st Lag	1st & 2nd Lag	ARIMAX
MAPE	1.17%	1.21%	1.70%	.57%	.54%	1.02%
RMSE	9415.13	9796.44	14183.91	5310.05	5063.56	8875.71

Table 30 presents the performance metrics across the various model sensitivities for the SGSS model. The multicollinearity exclusion sensitivities provide insight into the trade-offs of removing highly correlated variables. Excluding GDP-SS results in only marginal performance degradation, while eliminating the multicollinearity issue, suggesting this variable may provide somewhat redundant information given the presence of 2.1 Customers. In contrast, excluding 2.1 Customers leads to worse performance, indicating this variable captures important information about sales patterns that GDP-SS cannot fully replicate. This asymmetry suggests that customer counts may be the key driver of SGSS.

The lag inclusion models demonstrate improvements in forecast accuracy, mirroring the patterns observed in the residential class. However, as discussed previously, the in-sample fit of autoregressive models must be interpreted cautiously given overfitting concerns. The inclusion of the first lag eliminates the autocorrelation issue and improves overall performance. However, the marginal gains from including the second lag suggest diminishing returns in accuracy, indicating it is most likely not worth incorporating multiple lags.

The ARIMAX specification achieves moderate improvement over the base model. This performance mirrors the residential sales class. As discussed in earlier sections, the ARIMAX framework's structural approach to handling time series properties may provide more reliable long-term forecasts.

Figure 8 below depicts the forecasted values from 2023 to 2028 for the NPI base model as well as the various sensitivities.

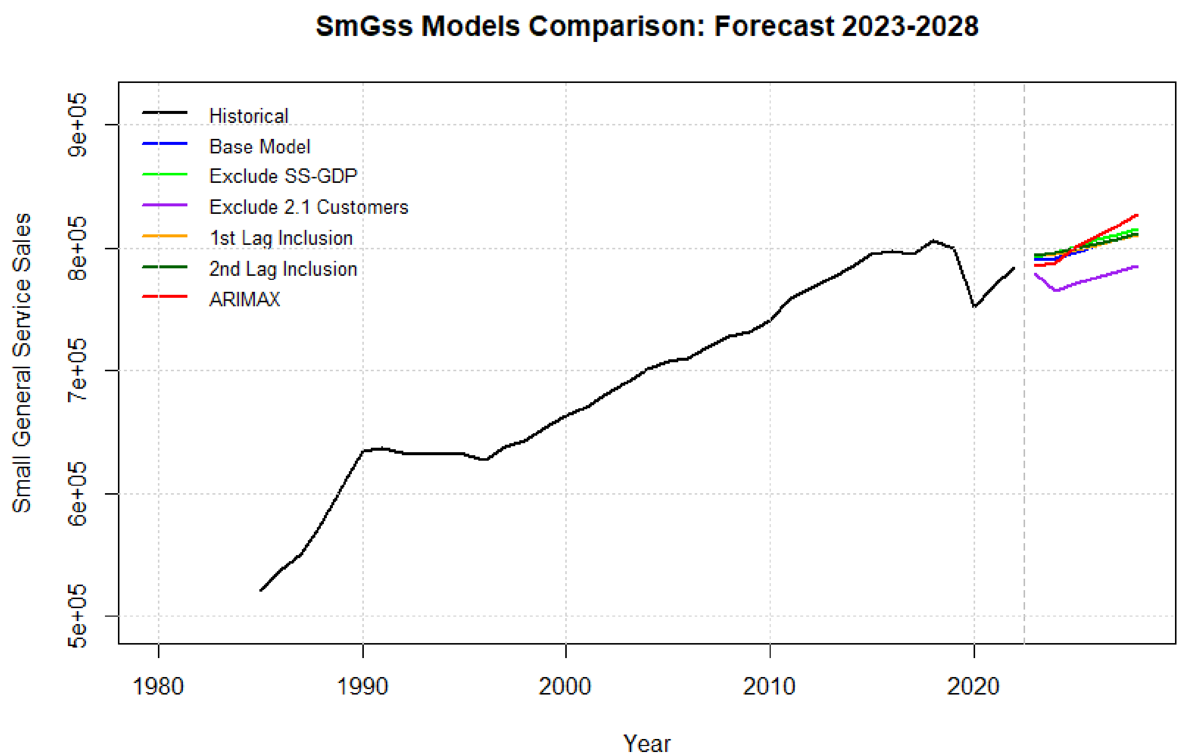


Figure 8: Forecasted Values from 2023 – 2028 for the NPI Base Model

All sensitivities outside of the exclusion of 2.1 Customers provide similar forecast results. This suggests that the base model performs reasonably well in capturing the fundamental dynamics of SGSS. The analysis also suggests that Newfoundland Power should consider removing GDP-SS from their specification. Doing so would make the model more efficient by eliminating one of the highly multicollinear variables while maintaining nearly equivalent forecasting performance. Newfoundland Power should continue testing the performance of this model specification along with any other sensitivities deemed as reasonable alternative models.

External Adjustments

Similar to the Residential Sales model, Newfoundland Power applies adjustments to SGSS to account for CDM, electric vehicles, and reconciliations for year-to-date actuals. The process for these adjustments remains similar as well with no specific cause for concern. A summary of these adjustments is provided in Table 31.

Table 31: Summary of Small General Service External Adjustments (GWh)

Year	Reconciliation	CDM	Electric Vehicles
2023	3.0	(1.4)	0.2
2024	3.0	(4.2)	0.7
2025	3.0	(7.7)	1.4
2026	3.0	(11.1)	2.5
2027	3.0	(14.5)	4.1
2028	3.0	(18.0)	6.3

The reconciliation adjustment represents approximately 0.4% of unadjusted forecast sales in each year while the impacts of CDM and electric vehicles are negligible.

Large General Service Sales

The LGS Sales model functions reasonably well with an error rate of 3.5% or less, as demonstrated in Table 32. The overestimate in 2024 is largely driven by the load associated with the expected transition of Memorial University from oil to electric boilers, which has been delayed.

Table 32: Large General Service Sales Error (GWh)

Sales	2023	2024	2025
Forecast[36]	1,466	1,496	1,591
Actuals[37]	1,459	1,462	
Error	(7)	(34)	
Error (%)	(0.5%)	(2.3%)	

Given the performance of the model, further adjustments and refinements are not a high priority at this time. However, Newfoundland Power may benefit from transferring Rate 2.3 to an econometric model. Given the relatively large volume of customers in this rate class, exceeding 1,000 customers, Newfoundland Power could employ an ARIMAX model with an explanatory variable that tracks a sub-section of provincial GDP. Employing an econometric model in this case could unlock time savings that render the forecasting process more efficient.

External Adjustments

The LGS Sales model accounts for the impacts of electric vehicles, electric heating conversion, CDM and year-to-date actuals, using a similar methodology to that modelled for the Residential and SGS classes.

Street Lighting

Daymark did not review the street-lighting model in detail. Given the relatively small magnitude of the class as well as the end-use forecasting methodology, Daymark does not expect that further modification of this forecast is a priority.

Peak Forecast

The Peak Demand model functions reasonably well with an error rate of 2.7% or less, as demonstrated in Table 33 below. Acknowledging that Newfoundland Power's load forecast is primarily a tool to ensure appropriate cost recovery of power purchases, the peak forecast is less relevant as a tool for its planning purposes. Given this information, Daymark does not believe further examination or refinement of the peak forecast model is a priority at this time.

[36] CED Forecast Report, 2025/2026 General Rate Application, Appendix B – Customer and Energy Forecast

[37] CED Forecast Summary, April 18, 2025

Table 33: Peak Demand Error (MW)

Sales	2023	2024	2025
Forecast[38]	1,448	1,476	1,469
Actuals[39]	1,487	1,458	
Error	39	(19)	
Error (%)	2.7%	-1.2%	

Key Uncertainties

While the current forecasting approach produces a reasonable forecast for Newfoundland Power's planning purposes, there are several factors that may influence the forecast that are not currently considered in the underlying models, such as the variability of weather. Furthermore, factors that may be included in current models could evolve in ways that diverge from current expectations. Daymark offers a few uncertainties for Newfoundland Power to consider in the future.

Weather

Newfoundland Power currently does not include weather as an independent variable in any of its forecasts, electing to use weather normalized data as an input. As such, while it is implicitly accounting for weather within its forecasts, it is not capable of testing weather sensitivities. While overall supply reliability is the responsibility of Hydro, the ability to test for weather variability may provide Newfoundland Power with the necessary data to produce risk management strategies from a resource planning or ratemaking perspective.

Electric Vehicles and Peak Impacts

As electric vehicle penetration increases, the associated loads could begin to shift the daily peak of the Newfoundland Power system. Furthermore, these impacts could vary from region to region, resulting in variable daily peaks across the island. Particularly if this shift happens quickly, it is unclear that the current peak forecasting methodology would be able to account for any peak shifting impact from this load source without an external adjustment to the peak forecast.

[38] CED Forecast Report, 2025/2026 General Rate Application, Appendix C – Purchased Energy and Demand Forecast

[39] CED Forecast Summary, April 18, 2025

V. DISCUSSION OF BRATTLE RECOMMENDATIONS

Brattle provided recommendations on the CED Forecast process during the 2025/2026 General Rate Application (see below). Given the analyses detailed above, Daymark finds that Newfoundland Power's CED Forecast performs well, with acceptable error rates at both the system and class level. However, this performance does not necessarily preclude critique or the possibility for improvement. Acknowledging that, Daymark provides commentary on the application of Brattle's recommendations to the CED Forecast.

Brattle Finding 1: Newfoundland Power has not provided sufficient information in its regulatory reporting

Full language: *The Company only provides a very high-level description of its load forecasting models in its GRA filing. The Company should, at a minimum, be required to submit a report that details their forecasting methodology, regression specifications and functional forms, estimated model coefficients along with standard errors, and alternative model specifications explored before settling on the final methodology for the forecasts. This report should also provide a detailed discussion of all of the ex-post model adjustments and the basis for the levels of these adjustments*.

Response: Daymark and Newfoundland Power agree that a more comprehensive report would be beneficial to the PUB and to those parties interested in understanding Newfoundland Power's approach to load forecasting. As discussed in Daymark's recommendations, prior to receiving regulatory feedback on load forecast models, Newfoundland Power must first be able to rigorously explain the philosophy, structure, and assumptions underlying each model with statistical descriptions to support this explanation. Lacking this level of detail, regulators and other intervenors will not be able to reasonably understand the intricacies of each model nor provide constructive feedback at the level of detail that is necessary.

Section IV provides a reference for the level of detail that is appropriate for regulatory reporting, but regulatory filings from neighboring utilities can also be used to inform the Newfoundland Power's final CED report. APPENDIX A of this report includes significant detail on the additional modeling Daymark undertook in reviewing both Newfoundland Power's load forecasting methodology and results. We recommend that the model developed by Daymark, along with the guidance in APPENDIX A be used as a starting point for Newfoundland Power producing a more detailed report moving forward.

Brattle Finding 2: Newfoundland Power has under-forecast, implying overcollection of revenues

Full language: *The Company has under-forecasted its domestic load four out of five times during the last five-year period, which implies that the Company was able to collect more revenues from the domestic class as a result of under forecasting domestic sales.*

Response: Daymark has not seen evidence of a consistent, systematic under-forecast. Appendix D of the *Customer, Energy and Demand Forecast* portion of the *Newfoundland Power – 2025/2026 General Rate Application*, titled "Comparison of Forecast Energy Sales to Weather Adjusted Actual Sales" shows that forecasts vary by -1.2% to 1.5% for real versus forecast values, resulting in an average of -0.3%. While this does represent a slight under forecast, Daymark does not view this underestimation as a systematic issue that is likely to impact ratepayers at this time, given the fluctuations between over and underestimation.

While Daymark identified underestimation bias in the Residential models, much of this bias was corrected for via external adjustments. As discussed in Table 15, the total CED Forecast produced an overestimation of energy needs for 2023 and 2024. As such, the Company should continue to refine its model in the future via the analysis of model error, but there is not sufficient evidence at this time to suggest a systematic underestimation bias when accounting for the entirety of the model methodology.

Brattle Finding 3: Newfoundland Power should use monthly data for forecasting

Full language: *The accuracy of the model would improve if the Company used monthly data in its econometric forecasting model instead of annual data.*

Response: Daymark agrees that the inclusion of more data points, as would occur if Newfoundland Power were to use monthly data, could improve the accuracy of the model. However, there are several concerns with this conversion that warrant further consideration before a determination of whether this recommendation should be implemented.

It is unclear whether all independent variables are available to Newfoundland Power monthly. For example, the CDM variable is only reported annually and would need involvement from multiple parties to be transformed into a monthly time series. Certain constructed variables, such as the market share of electric heating, would also require further analysis to produce a reasonable time series. The process of developing a monthly time series would require significant time while the impact of this transition on forecasting accuracy is not immediately clear, rendering the return on this investment uncertain. This is particularly relevant since the load forecast has proven to be highly accurate over time, as discussed in Section IV above.

Additionally, depending upon the level of sustained work that would be needed to produce monthly input data, this could incur additional costs that would be borne by Newfoundland Power ratepayers, which would need to be considered in conjunction with any benefits that could be realized from a change to their existing process. Given that one of the purposes of the Newfoundland Power load forecast is to set customer rates these costs may not be justified without a clear indication of expected benefits.

Daymark recommends that Newfoundland Power include the potential for moving to monthly modeling in future test cycles, following the establishment of a testing and validation regime. Over time, various portions of the model could be tested with monthly units of observation as data availability improves, allowing for the verification that this transition does not reduce model performance or produce a net increase in customer costs.

Brattle Finding 4: Newfoundland Power should include CDD and HDD, possibly on a monthly level

Full language: *The model is missing a key determinant of electricity sales, which is the weather variable and the Company should consider adding CDD and HDD variables to the model, on a monthly level.*

Response: Newfoundland Power's forecasting methodology already incorporates the impact of weather by using weather normalized historical consumption data. As such, including a weather variable in the regression model would not be appropriate without additional changes to the overall methodology. Additionally, it is unclear that sufficient forecasting data is available to Newfoundland Power to use as independent variable in its regression model.

In the context of actual weather data, including weather as an independent variable would allow Newfoundland Power to not only account for the impacts of weather on power needs, but also test sensitivities on weather variability. However, given the general accuracy of the CED model, it is unclear that shifting the model to use actual consumption data and include weather variables would necessarily improve model performance at this time.

Daymark recommends that Newfoundland Power determine the potential impacts of modifying the approach to incorporating weather in its modeling methodology in future test cycles.

Brattle Finding 5: Newfoundland Power may have an endogeneity problem related to the price of oil in its model

Full language: *The Company's finding that the price of oil has a negative coefficient upon including it in their main specification does not prove that the price of oil does not belong in the energy sales model. It potentially indicates that there is an endogeneity problem in the regression leading to biased and inconsistent estimates for the other variables in the model.*

Response: Oil is not a perfect substitute for electricity with regards to heating in the Newfoundland context given the significant switching costs between the two technologies.[40] Historically, the predominant type of electric heating in Newfoundland has been electric baseboard heating. Oil furnaces require completely different household infrastructure, including an oil furnace, an oil tank, and in-wall ducting/hot water/steam distribution systems. The costs incurred in installing an oil furnace to replace baseboard heaters in response to higher electric heating costs would be significant and have not been observed to have occurred in any meaningful way.

Furthermore, electric heating policy goals and incentives, such as the takeCHARGE! Oil to Electric Incentive Program, are creating a shift away from oil heating towards heat pumps. Therefore, it is more likely that households using electric baseboard heaters, or even those currently using oil furnaces, are likely to switch to this lower consumption electric option.

Much of these impacts may already be captured in the residential average use model though the electric heating market share variable. As discussed in Newfoundland Power's responses to requests for information,[41] the price of oil is correlated with not only the market share variable, but also the price of electricity. Including the price of oil in the model may go as far as to introduce issues of multicollinearity. Newfoundland

[40] Perfect substitutes, such as two brands of water at the grocery store, are completely interchangeable with no barriers to consumers selecting between the two goods. As such, consumers will make decisions based predominantly on price. Oil and electricity, by contrast, are not perfect substitutes, as switching between the two requires the installation of specific equipment, consideration of government policy/subsidies, the price volatility of the goods, and other factors, including non-price impacts such as customer preference.

[41] Newfoundland Power Response to PUB-NP-155

Power notes a number of other limitations to the inclusion of the oil price variable within its model in its response.

Daymark finds that further testing of the oil price variable is not a high priority at this time. Based on the context above, it is unclear whether there is an endogeneity issue related to this variable with the potential for introducing new biases following the its inclusion. Employing the Durbin-Wu-Hausman test or an augmented regression test will allow Newfoundland Power to verify if there is a clear endogeneity issue within its testing regime.

Brattle Finding 6: Newfoundland Power should submit detailed documentation regarding its approach for modeling CDM and electrification

Full language: *We understand that the Company's sales forecasting framework accounts for the impacts of CDM and electrification, but it is unclear whether this accounting is done correctly. As with the overall framework, the Company should submit detailed documentation describing the approach for the impacts of CDM and electrification, and ensure that there is no overadjustment for these impacts in the forecast. The same holds true for the Company's forecasts for electric vehicles.*

Response: Daymark agrees with Brattle Group on this recommendation that Newfoundland Power should submit more detailed documentation describing its forecasting assumptions. Additional details regarding the CDM plan would increase confidence in Newfoundland Power's load forecasting approach.

Brattle Finding 7: Newfoundland Power should document how it uses price elasticity in its modeling

Full language: *In its response to PUB-NP-159, the Company indicates that estimates for price elasticity are derived from the econometric models for energy sales forecasting. However, it does not detail exactly how these were obtained. Moreover, it references another report by Dr. James P. Feehan that analyzed price elasticity for the Company's Domestic customers using annual data from 1992 to 2016. This study uses a fairly robust framework for estimating elasticity. However, it is unclear if the Company directly uses estimates from this work in its own forecasting process.*

Response: Daymark agrees with Brattle Group on this recommendation that Newfoundland Power should provide more documentation describing how it uses price elasticity in its CED Forecast. The references provided in Newfoundland Power's CED Forecast are not sufficient to fully describe the approach taken in estimating price elasticity. Newfoundland Power should clearly detail the methodology employed to determine price elasticity, and provide specific references to cited works, where appropriate.

Brattle Finding 8: Newfoundland Power should consider using an econometric model for forecasting peak demand

Full language: *For system peak demand, the Company should explore an alternative approach to test the robustness of its results using an econometric model, as it does with total energy sales.*

Response: Daymark finds that Newfoundland Power's peak demand forecast methodology is reasonable for its intended purpose. Supply resource adequacy planning for Newfoundland is completed by Hydro. Newfoundland Power is more concerned with its purchased power forecast to ensure that it is setting rates appropriately to ensure financial recovery of power (energy and demand) purchased from Hydro.

Brattle Finding 9: Newfoundland Power should utilize granular level peak forecasts to calibrate the system level peak forecast

Full language: *The Company should aggregate its granular area level, substation, and feeder-level peak demand forecasts and compare them with those obtained from its existing approach. Doing so will provide an additional data point for the Company to calibrate its peak demand forecasting methodology against.*

Response: Daymark disagrees with this recommendation given that Newfoundland Power's granular area level, substation, and feeder-level peak demand forecasts are not independently produced but are instead an output of its system peak demand forecasting methodology. As such, there is no independent data point for the Company to calibrate.

Brattle Finding 10: Newfoundland Power should account for the impact of demand-side management (DSM) on system peak

Full language: *Just as the Company accounts for the impact of increasing CDM and electrification separately in its energy sales forecasts, it should conduct a similar exercise for the impact of demand-side load modifiers on system peak demand.*

Response: Newfoundland Power shows acceptable accuracy through the current peak forecasting methodology. Further testing is necessary to determine if accounting for the impacts of DSM load modifiers will meaningfully affect system peak demand, necessitating a methodological shift.

VI. DAYMARK RECOMMENDATIONS

Having conducted a full review, analysis, and testing process on the CED Forecast, and reviewing the recommendations provided by Brattle, Daymark determines that Newfoundland Power's CED Forecast is reasonable given its ability to forecast both energy and peak demand within error rates less than 3%. It is unclear at this time that Newfoundland Power could significantly improve the accuracy of its forecast without first taking some preliminary steps:

1. Modernize the Forecast Environment

First, Newfoundland Power should explore shifting from a spreadsheet-based forecasting environment into a modern econometric program. Forecasting in a program such as Microsoft Excel offers significant limitations to the testing of alternate models as well as the running of specific statistical tests. While these acts are theoretically possible within a spreadsheet, they are significantly more difficult, requiring more time and ultimately more cost.

Daymark recommends that Newfoundland Power explore available statistical programming software and select a package that fits its needs. While Daymark used R to run the models in this report, software such as EViews or Python are also used across the utility industry. The selection of a specific software program will depend on the coding knowledge, familiarity with statistical concepts, and the cost of the specific program.

2. Establish a Testing and Validation Regime

Following a modernization of Newfoundland Power's forecasting software, it should establish a system to more thoroughly test the performance of its forecasting models. Daymark demonstrated a variety of methods to test the performance of Newfoundland Power's forecasting models, including the examination of:

- Accuracy of forecasted customers, energy, and demand;
- Accuracy of econometric models via MAPE or RMSE;
- Testing of alternate model specifications;
- Validation of underlying assumptions with data from comparable geographies; and
- Statistical validation of econometric assumptions such as homoskedasticity and stationarity.

By establishing a process by which Newfoundland Power is regularly testing and refining its forecast models, it can iteratively improve the models to ensure reasonable performance and accuracy is maintained.

3. Expand Level of Detail in Regulatory Reporting

The results of the testing and validation, and expanded descriptions of model philosophy should be included in Newfoundland Power's reporting to the regulator. Daymark's analysis of the underlying forecast models provides a reference point for how Newfoundland Power can approach expanding the level of detail provided in its reporting to include detailed views of forecast outputs, statistical testing, model accuracy, explanations of model selection, and more.

Within the context of regulatory reporting, Newfoundland Power should ensure that the structure of each model is not only explained mathematically but also philosophically. For example, given an econometric model that uses independent variables of price and lagged consumption to inform a forecast of future consumption, Newfoundland Power should be able to explain how each of these variables is correlated to the dependent variable in real world terms. This explanation should also include a discussion of other variables that were considered in the generation of this model and why they were not ultimately selected.

4. Test and Consider Eliminating 2022+ Variable from Model

Newfoundland Power does not have sufficient justification for using the 2022+ variable at this time and should consider eliminating such a variable. Currently, this variable provides a one-time increase to average usage or sales, depending on the model. This may be inappropriately removing explanatory power from other independent variables in the Residential Average Usage and SGSS models, resulting in unreliable coefficients and potentially biased forecasts.

The Company should test the removal of this variable, examining how this vintage of the model performs against actuals in 2023 and 2024. If this specification continues to perform well, the Company should consider eliminating this variable in its next regulatory filing.

5. Identify Clear Reasons for Variable Transformations

Any variable that is expressed as an index or otherwise transformed from its original units, should have a clear rationale attached. For example, transformed time series to a natural log basis allows a modeler to interpret the coefficients of a regression model output as a percentage, while accounting for any issues of non-stationarity. To this end, Newfoundland Power can test and validate the implementation of a natural log transformation on all non-dummy variables in its econometric models.

This reasoning is less evident for something like the CDM variable. In the Residential Average Use model, CDM is indexed to 1992, rather than directly representing the energy savings associated with CDM programs. As a result, the coefficient of the CDM is difficult to directly interpret and may produce unreliable coefficient estimates.

Newfoundland Power should test how re-specifying model variables impacts its forecast and review its independent variables to ensure that they are specified in units that are easily interpretable. The results of these tests and the decisions made should then be documented to assist interested parties in interpreting the model and methodology.

APPENDIX A Daymark CED Model Details

I. RESIDENTIAL AVERAGE USAGE

In this section, further statistics and residuals are presented for the base Residential Average Usage model used by Newfoundland Power as well as each sensitivity tested by Daymark.

A. NPI Base Model

Variable	Coefficient	Std. Error	t-value	p-value	Sig.[42]
(Intercept)	8909.256	484.945	18.372	<0.001	***
Market Share	18665.130	533.143	35.010	<0.001	***
Marginal Price Index	-25.396	6.573	-3.863	<0.001	***
Marginal Price Index Lag	-17.699	6.933	-2.553	0.015	*
CDM Index	-101.425	6.369	-15.926	<0.001	***
2022+	325.121	219.900	1.478	0.148	
Income Per Customer	3.648	4.351	0.838	0.408	
2020	356.497	204.594	1.742	0.090	.

Model Statistics

Observations: 43

Residual Standard Error: 174.8 on 35 degrees of freedom

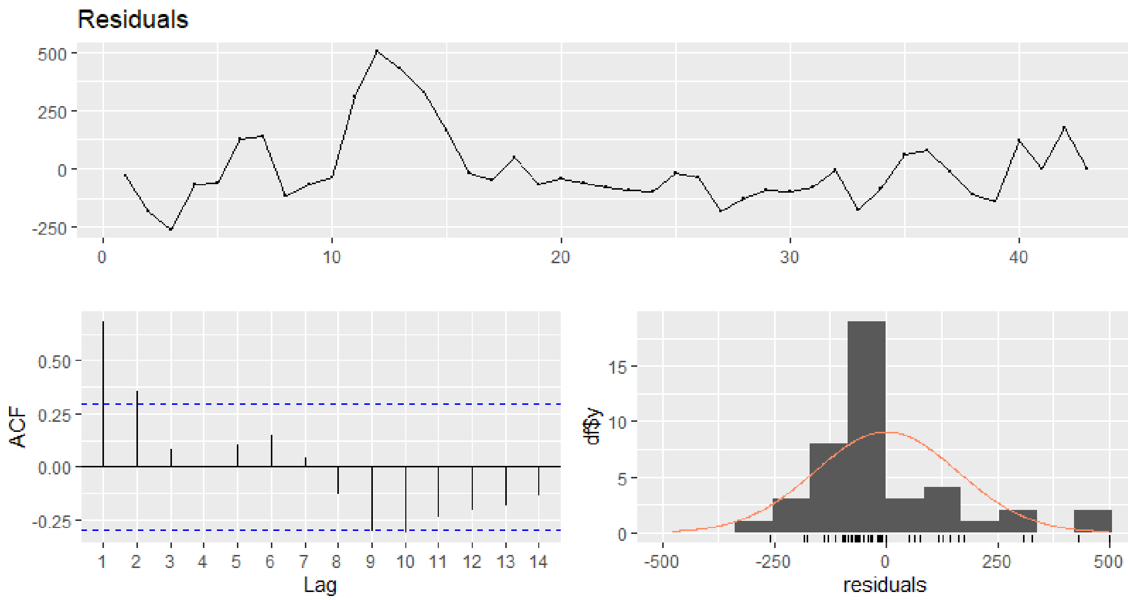
R-squared: 0.9831

Adjusted R-squared: 0.9797

F-statistic: 290.5 (df = 7, 35), p-value < 0.001

[42] The column marked "Sig." refers to the significance of a given coefficient, with one asterisk corresponding to statistical significance at the 0.1 level, two asterisks corresponding to significance at the 0.05 level, and three asterisks corresponding to significance at the 0.01 level.

Residuals



B. Sensitivity #1: Log – Log Specification

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	11.561	0.158	73.272	<0.001	***
Log Market Share	0.659	0.016	41.586	<0.001	***
Log Marginal Price	-0.191	0.042	-4.544	<0.001	***
Log – Lag Marginal Price	-0.157	0.045	-3.521	0.001	**
CDM Index	-0.005	0.000	-14.854	<0.001	***
2022+	0.019	0.013	1.455	0.155	
Income Per Customer	0.001	0.000	2.696	0.011	*
2020	0.022	0.012	1.740	0.091	.

Model Statistics

Observations: 43

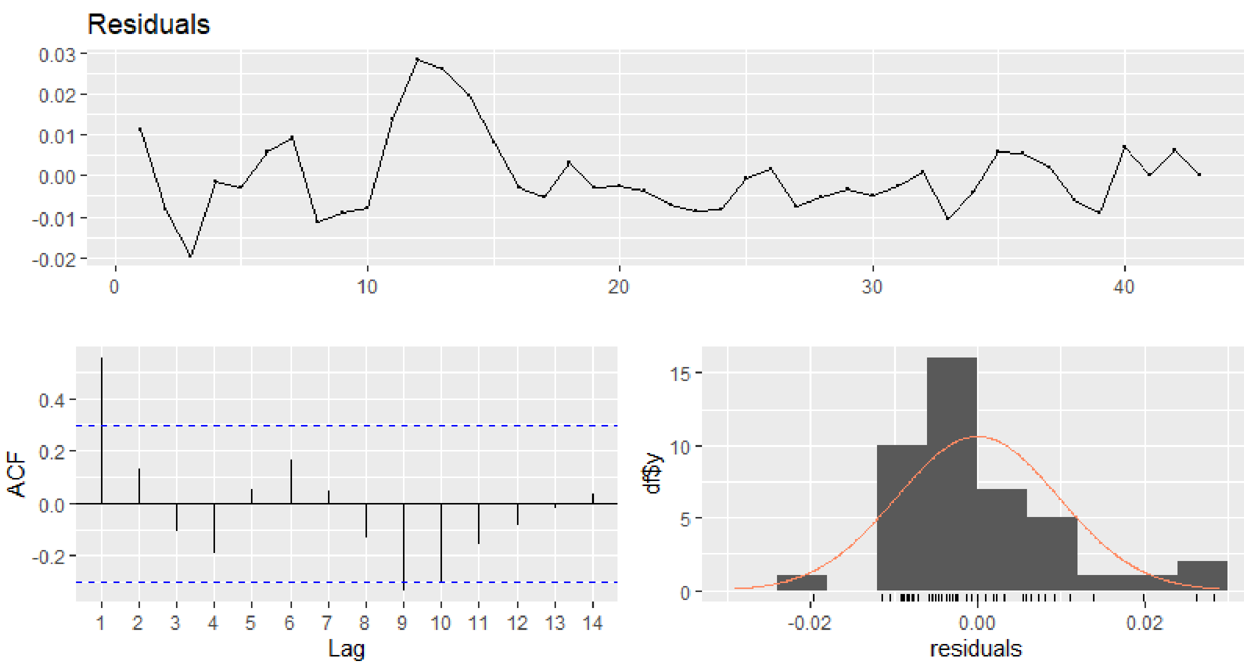
Residual Standard Error: 0.01062 on 35 degrees of freedom

R-squared: 0.9879

Adjusted R-squared: 0.9855

F-statistic: 407.7 (df = 7, 35), p-value < 0.001

Residuals



C. Sensitivity #2: Log Model with Lag dependent variable

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	5.977	0.998	5.991	<0.001	***
Lag Average Usage	0.478	0.085	5.612	<0.001	***
Log Market Share	0.324	0.062	5.201	<0.001	***
Log Marginal Prices	-0.151	0.031	-4.847	<0.001	***
Log – Lag Marginal Prices	-0.027	0.040	-0.680	0.501	
CDM Index	-0.003	0.000	-7.525	<0.001	***
2022+	0.027	0.010	2.838	0.008	**
Income Per Customer	0.001	0.000	3.916	<0.001	***
2020	0.021	0.009	2.351	0.025	*

Model Statistics

Observations: 42 (1 deleted due to lagged variables)

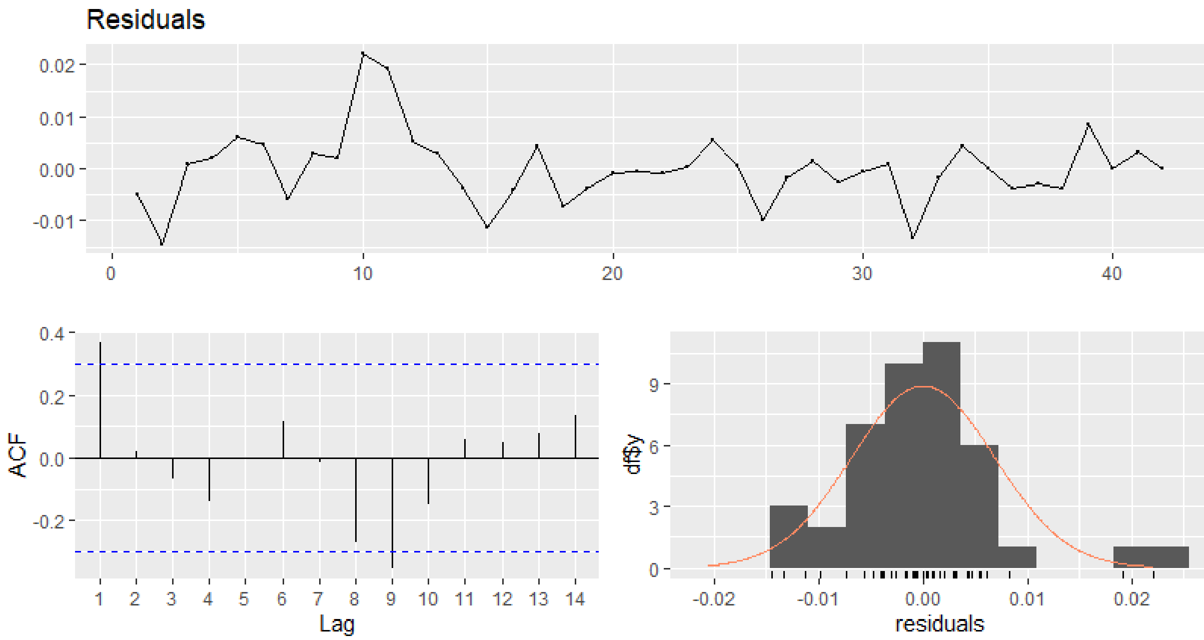
Residual Standard Error: 0.007649 on 33 degrees of freedom

R-squared: 0.993

Adjusted R-squared: 0.9913

F-statistic: 586.2 (df = 8, 33), p-value < 0.001

Residuals



D. Sensitivity #3: Log Model with lag dependent variable and second lag dependent variable

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	3.826	0.770	4.970	<0.001	***
Lag Average Usage	1.076	0.134	8.034	<0.001	***
Second Lag Average Usage	-0.449	0.107	-4.211	<0.001	***
Market Share	0.463	0.106	4.357	<0.001	***
Log Marginal Prices	-0.179	0.032	-5.526	<0.001	***
Log – Lag Marginal Prices	0.074	0.035	2.152	0.039	*
CDM Index	-0.003	0.001	-5.255	<0.001	***
2022+	0.026	0.009	2.896	0.007	**
Income Per Customer	0.000	0.000	0.114	0.910	
2020	0.020	0.008	2.373	0.024	*

Model Statistics

Observations: 41 (2 deleted due to lagged variables)

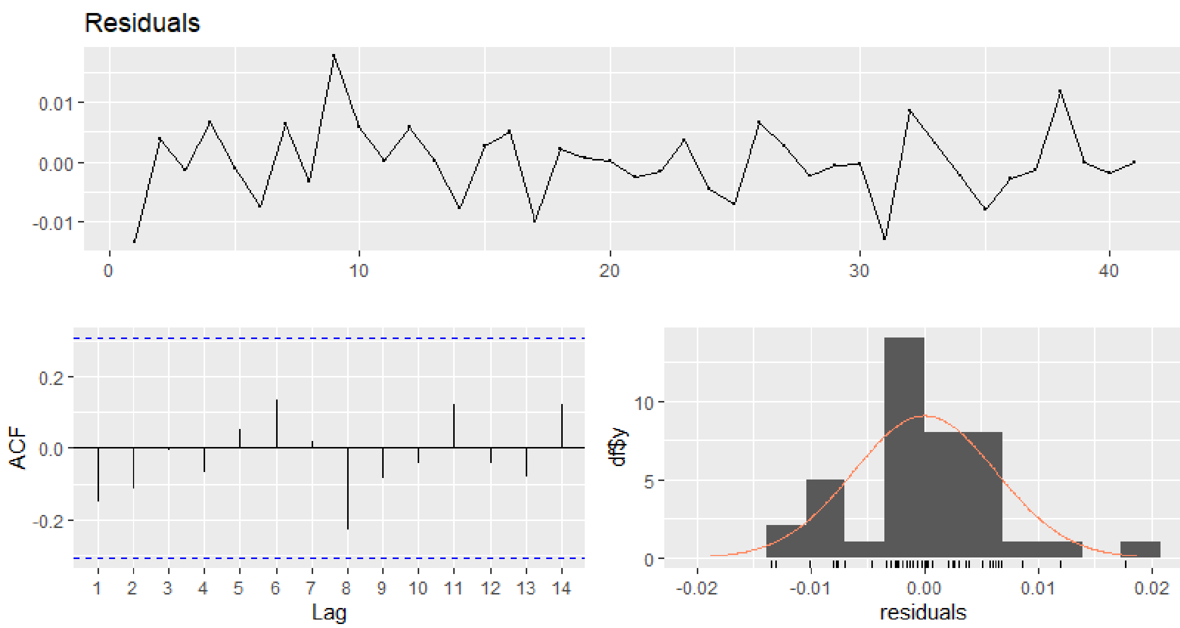
Residual Standard Error: 0.007111 on 31 degrees of freedom

R-squared: 0.9934

Adjusted R-squared: 0.9915

F-statistic: 516.6 (df = 9, 31), p-value < 0.001

Residuals



E. Sensitivity #4: Incorporation of Third lagged dependent variable

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	4.612	0.745	6.194	<0.001	***
Lag Average Usage	0.914	0.139	6.554	<0.001	***
Second Lag Average Usage	-0.289	0.171	-1.693	0.101	
Third Lag Average Usage	-0.059	0.101	-0.587	0.562	
Market Share	0.512	0.102	4.998	<0.001	***
Log Marginal Prices	-0.154	0.030	-5.146	<0.001	***
Log – Lag Marginal Prices	-0.007	0.039	-0.176	0.862	
CDM Index	-0.003	0.000	-6.249	<0.001	***
2022+	0.028	0.008	3.425	0.002	**
Income Per Customer	0.000	0.000	1.317	0.198	
2020	0.021	0.007	2.904	0.007	**

Model Statistics

Observations: 40 (3 deleted due to lagged variables)

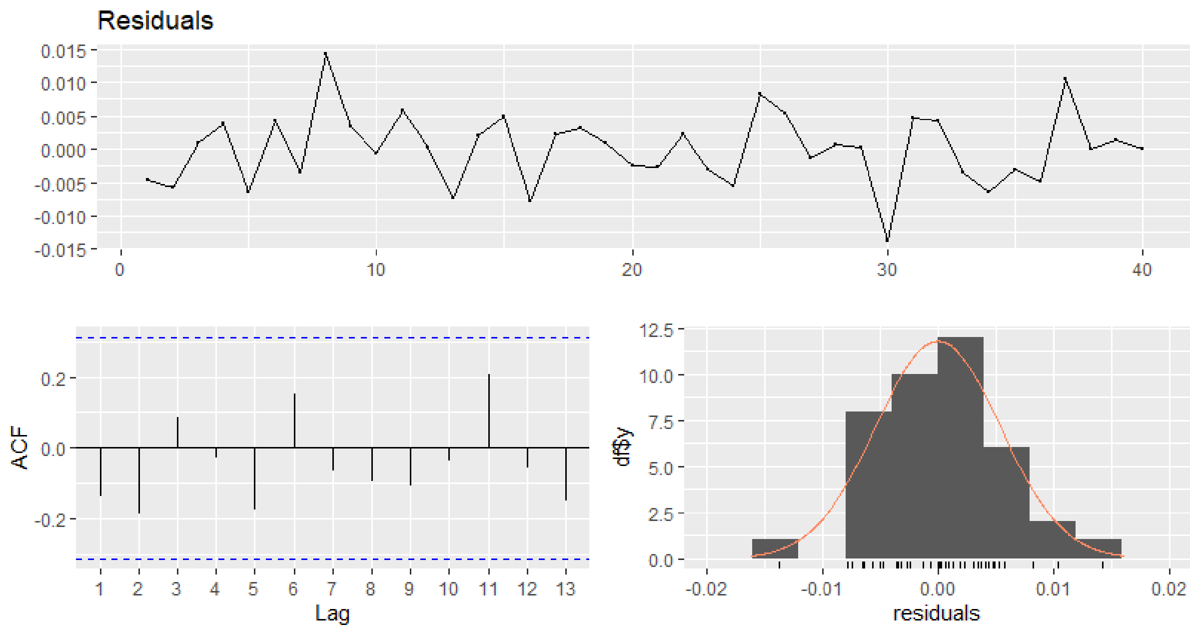
Residual Standard Error: 0.00625 on 29 degrees of freedom

R-squared: 0.9942

Adjusted R-squared: 0.9922

F-statistic: 494.2 (df = 10, 29), p-value < 0.001

Residuals



F. Sensitivity #5: Significant Variables Only

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	9098.286	427.567	21.279	<0.001	***
Market Share	18793.222	508.670	36.946	<0.001	***
Marginal Prices	-26.121	6.489	-4.025	<0.001	***
Lag Marginal Prices	-15.878	6.557	-2.422	0.021	*
CDM Index	-99.974	6.104	-16.379	<0.001	***
2020	327.367	200.788	1.630	0.112	
2022+	274.461	210.561	1.303	0.201	

Model Statistics

Observations: 43

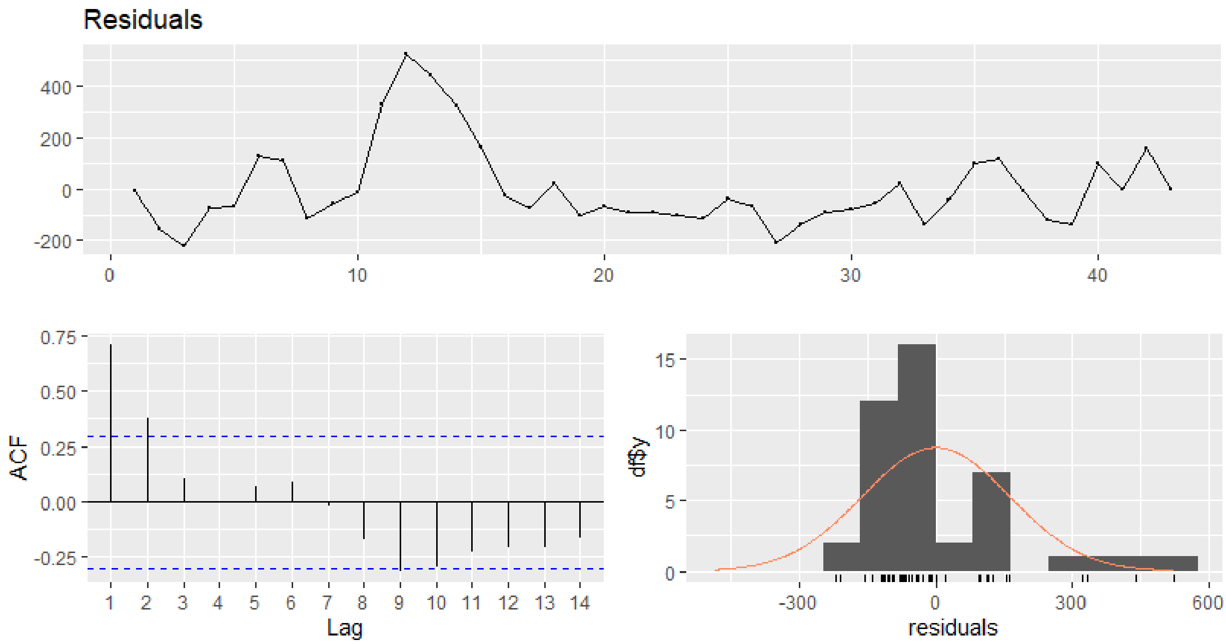
Residual Standard Error: 174.1 on 36 degrees of freedom

R-squared: 0.9827

Adjusted R-squared: 0.9799

F-statistic: 341.7 (df = 6, 36), p-value < 0.001

Residuals



G. Sensitivity #6: ARIMAX Model

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
Market Share	19696.89	1897.63	10.38	<0.001	***
Marginal Prices	-19.64	3.91	-5.02	<0.001	***
Lag Marginal Prices	-14.23	3.87	-3.68	<0.001	***
CDM Index	-100.78	15.66	-6.43	<0.001	***
2022+	97.08	124.79	0.78	0.441	
Income Per Customer	-4.26	6.02	-0.71	0.483	
2020	171.65	81.43	2.11	0.042	*

Model Statistics

σ² (Variance): 15140

Log Likelihood: -257.89

AIC: 531.78

AICc: 536.15

BIC: 545.68

Residuals

II. SMALL GENERAL SERVICE SALES

A. NPI Base Model

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	10790000	1502000	7.179	<0.001	***
GDP-SS	6.921	4.324	1.601	0.120	
Price 2002	-510.4	442.9	-1.152	0.258	
2022+	36750	15530	2.367	0.024	*
GSS CDM Index	-110500	15500	-7.125	<0.001	***
2.1 Customers	45.59	7.268	6.273	<0.001	***
2020	-18810	12890	-1.459	0.155	

Model Statistics

Observations: 38

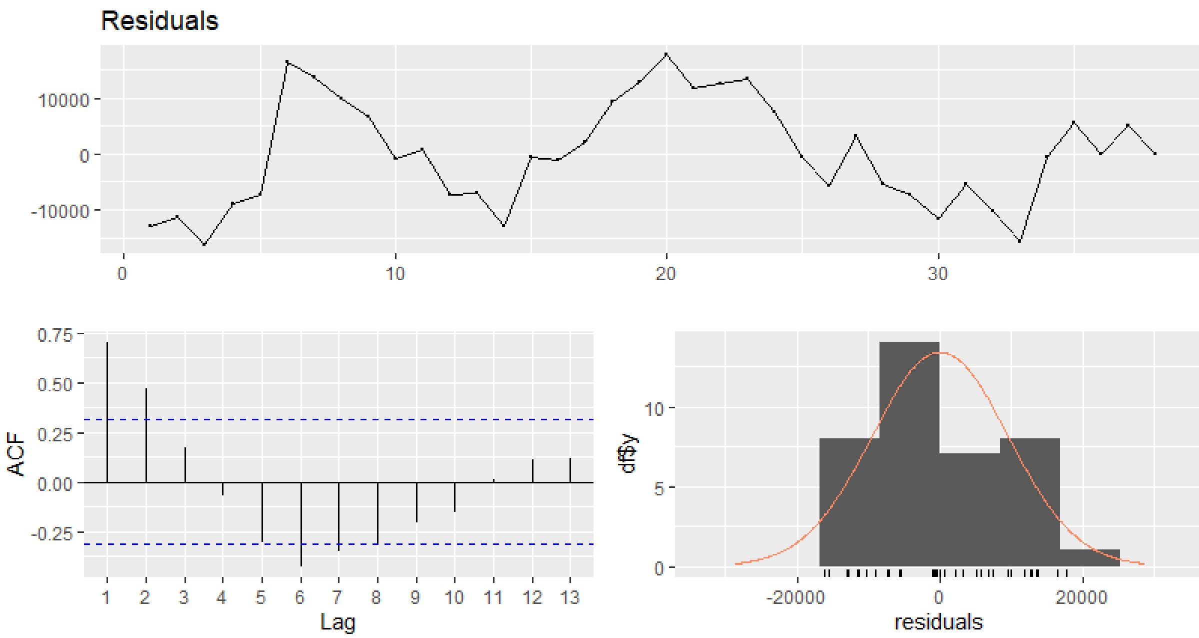
Residual Standard Error: 10420 on 31 degrees of freedom

R-squared: 0.9856

Adjusted R-squared: 0.9829

F-statistic: 354.7 (df = 6, 31), p-value < 0.001

Residuals



B. Sensitivity #1: Exclusion of SS GDP

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	11620000	1442000	8.060	<0.001	***
Price 2002	-352.3	442.1	-0.797	0.431	
2022+	40630	15710	2.586	0.015	*
GSS CDM Index	-120400	14550	-8.270	<0.001	***
2.1 Customers	56.79	2.013	28.207	<0.001	***
2020	-24510	12690	-1.931	0.062	.

Model Statistics

Observations: 38

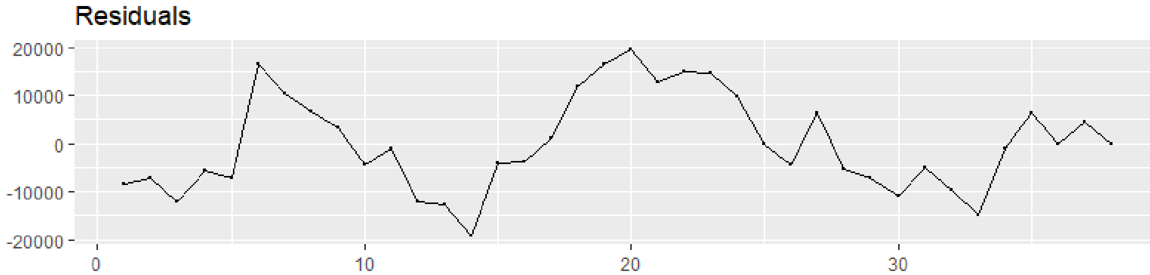
Residual Standard Error: 10680 on 32 degrees of freedom

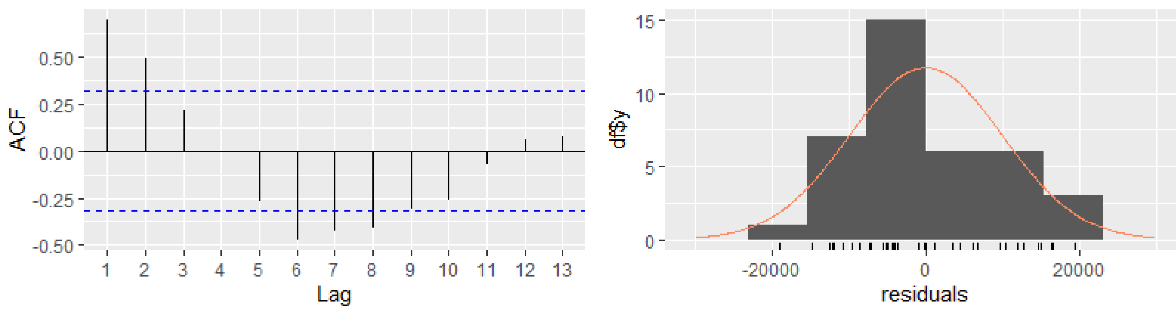
R-squared: 0.9845

Adjusted R-squared: 0.982

F-statistic: 405.4 (df = 5, 32), p-value < 0.001

Residuals





C. Sensitivity #2: Exclusion of 2.1 Customers

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	6651000	2002000	3.322	0.002	**
GDP-SS	33.03	1.734	19.047	<0.001	***
Price 2002	-1590	605.1	-2.627	0.013	*
2022+	18080	22600	0.800	0.430	
GSS CDM Index	-62140	19950	-3.115	0.004	**
2020	3278	18390	0.178	0.860	

Model Statistics

Observations: 38

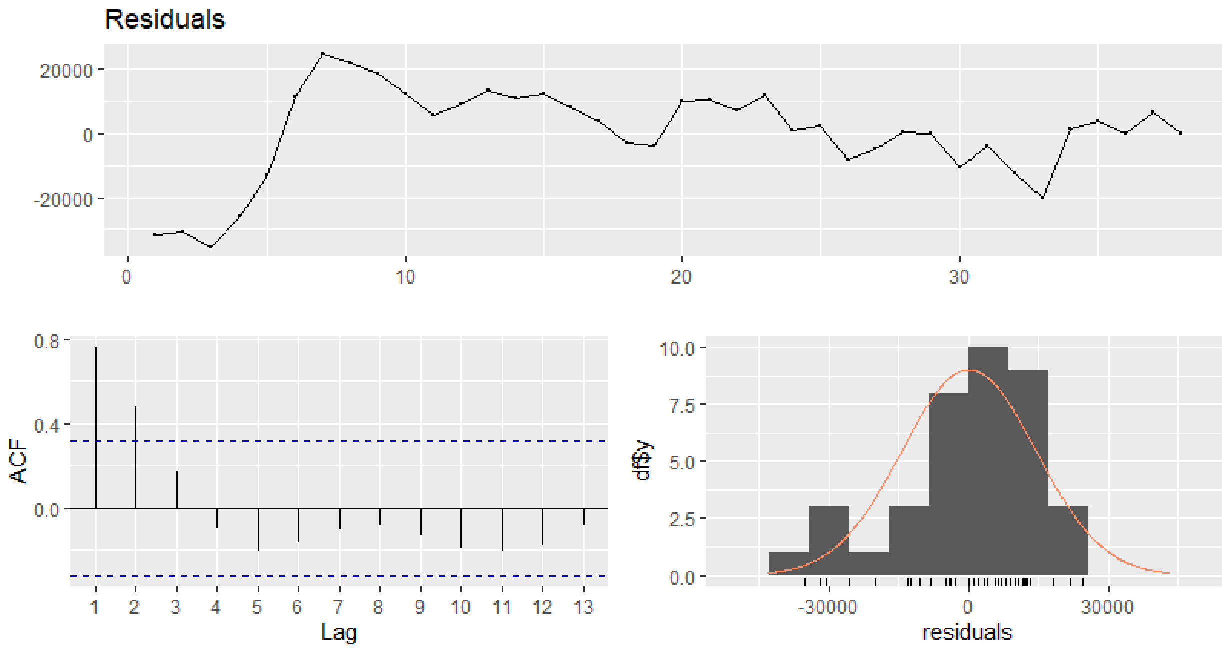
Residual Standard Error: 15460 on 32 degrees of freedom

R-squared: 0.9674

Adjusted R-squared: 0.9623

F-statistic: 190 (df = 5, 32), p-value < 0.001

Residuals



D. Sensitivity #3: Inclusion of lagged dependent variable

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	1760000	842400	2.089	0.045	*
GDP-SS	10.39	1.932	5.378	<0.001	***
Price 2002	-431.0	249.9	-1.725	0.095	.
2022+	9121	8663	1.053	0.301	
GSS CDM Index	-16100	8314	-1.937	0.062	.
2020	-36750	7646	-4.806	<0.001	***
Lagged GS Sales	0.665	0.054	12.393	<0.001	***

Model Statistics

Observations: 37 (1 deleted due to lagged variables)

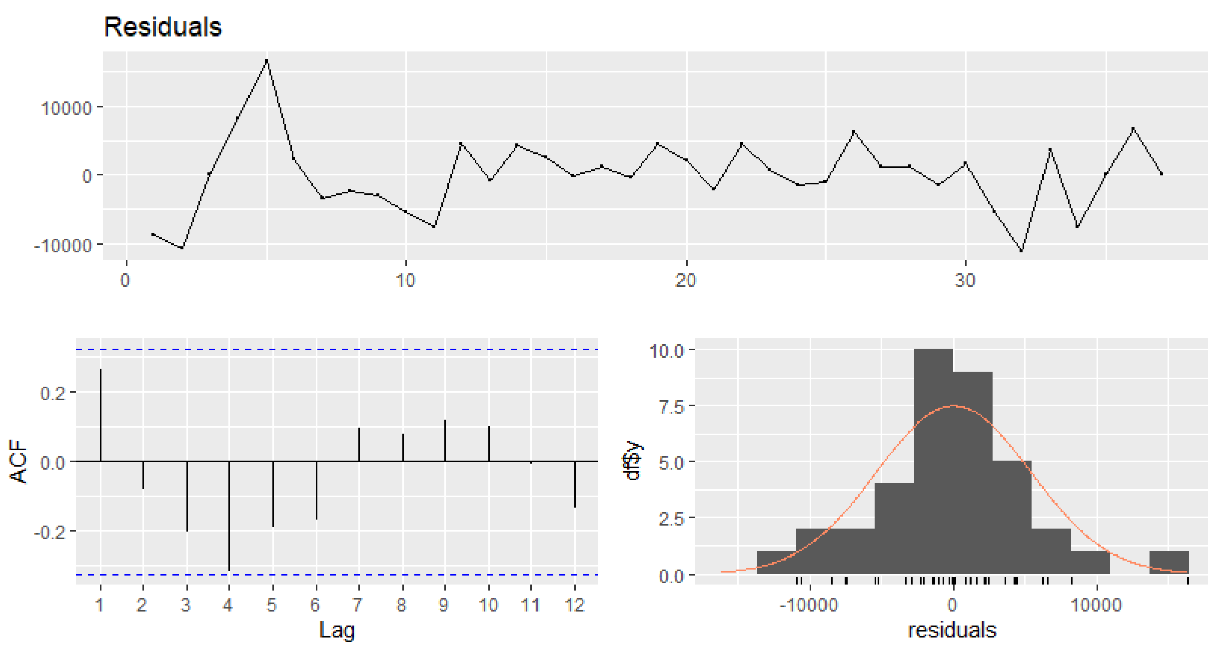
Residual Standard Error: 5897 on 30 degrees of freedom

R-squared: 0.9949

Adjusted R-squared: 0.9939

F-statistic: 975.9 (df = 6, 30), p-value < 0.001

Residuals



E. Sensitivity #4: Inclusion of first and second lagged dependent variables

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
(Intercept)	1247000	1137000	1.097	0.282	
GDP-SS	11.44	2.073	5.520	<0.001	***
Price 2002	-295.8	263.5	-1.123	0.271	
2022+	3222	11140	0.289	0.775	
GSS CDM Index	-11020	11190	-0.985	0.333	
2020	-37090	8026	-4.621	<0.001	***
Lag GS Sales	0.709	0.141	5.019	<0.001	***
Second Lag GS Sales	-0.077	0.115	-0.673	0.506	

Model Statistics

Observations: 36 (2 deleted due to lagged variables)

Residual Standard Error: 5742 on 28 degrees of freedom

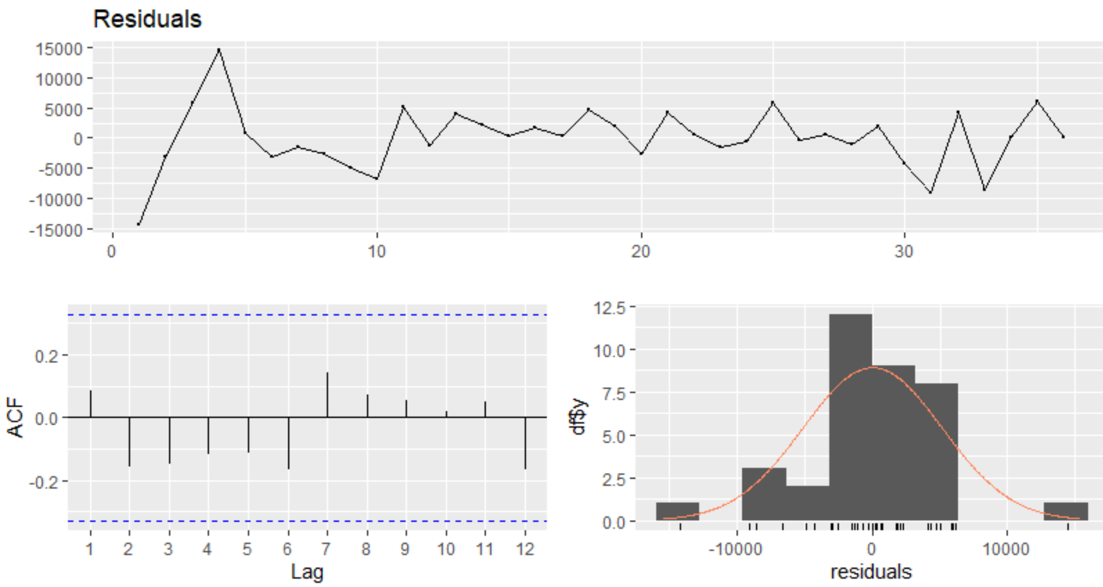
R-squared: 0.9948

Adjusted R-squared: 0.9935

F-statistic: 769.6 (df = 7, 28), p-value < 0.001

***Significance codes:** *** p<0.001, ** p<0.01, * p<0.05, . p<0.1*

Residuals



F. Sensitivity #5: ARIMAX Model

Variable	Coefficient	Std. Error	t-value	p-value	Sig.
drift	9068.20	1940.92	4.67	<0.001	***
gdp_ss_diff	17.21	14.38	1.20	0.239	
Price2002	-519.10	511.74	-1.01	0.318	
2022+	35208.09	10589.32	3.33	0.002	**
GSS_CDM_Index	-126107.12	726.99	-173.47	<0.001	***
custs_diff	-3.41	19.95	-0.17	0.865	

Model Statistics

σ^2 (Variance): 97,159,750

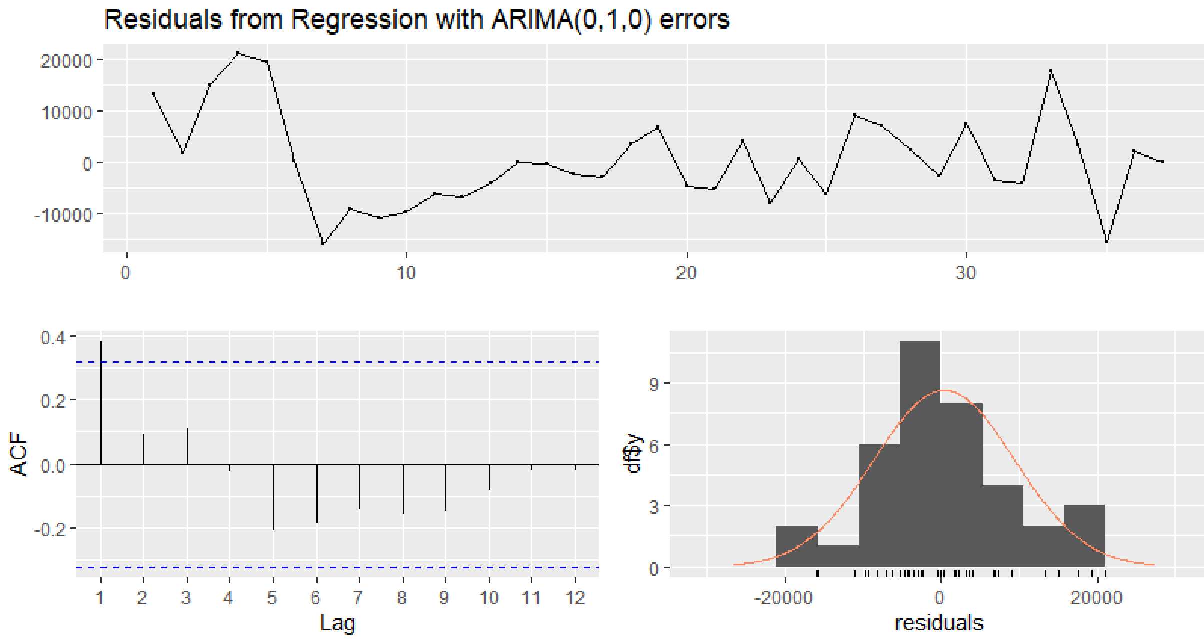
Log Likelihood: -377.75

AIC: 769.49

AICc: 773.49

BIC: 780.57

Residuals


Residuals from Regression with ARIMA(0,1,0) errors
20000
10000
0
-10000
0
10
20
30
0.4
0.2
ACF
0.0
-0.2
1
2
3
4
5
6
7
8
9
10
11
12
Lag
9
6
3
0
df$y
-20000
0
20000
residuals

G. Fitted Values For Average Usage Models

All values transformed from natural log to original scale where applicable

Year	NPI Base	Log-Log	1st Lag	2nd Lag	3rd Lag	ARIMAX
1980	11785.28	11623.11	-	-	-	11744.54
1981	12267.8	12184.61	12142.32	-	-	12212.63
1982	12321.61	12301.6	12237.22	12225.93	-	12220.30
1983	12354.83	12303.56	12276.95	12240.76	12346.17	12210.70
1984	12559.37	12537.18	12474.93	12517.29	12572.07	12549.50
1985	12461.35	12513.63	12510.84	12506.1	12576.79	12510.42
1986	12718.58	12742.26	12800.98	12873.51	12812.08	12861.55
1987	13256.48	13293.64	13217.65	13244.08	13227.79	13321.54
1988	13740.35	13797.31	13630.16	13585.86	13614.19	13576.96
1989	14240.51	14317.06	14176.6	14253.63	14256.14	14126.96
1990	14622.46	14724.59	14604.89	14667.48	14719.39	14575.54
1991	14645.19	14722.51	14859.25	15056.83	15094.87	15017.06
1992	14633.11	14673.6	14985.06	15061.23	15075.29	15165.68
1993	14684.94	14715.12	14964.84	14923.84	14923.99	15131.75
1994	14760.5	14801.78	14980.6	14921.88	14918.84	15076.77
1995	14768.37	14796.72	14919.64	14869.08	14862.79	14947.69
1996	14847.42	14871.52	14857.07	14759.53	14767.79	14845.28
1997	14763.22	14765.51	14748.27	14738.04	14742.47	14766.30
1998	14705.42	14684.27	14747.41	14788.32	14753.95	14779.88
1999	14650.92	14647.66	14664.57	14578.83	14575.52	14567.86
2000	14783.53	14777.06	14732.63	14711.72	14675.09	14737.33
2001	15003.36	15032.2	14936.29	14925.12	14912.47	14898.49
2002	15234.3	15277.54	15158.55	15182.52	15180.45	15145.14
2003	15418.27	15451.76	15316.24	15345.57	15362.23	15347.99
2004	15461.68	15454.89	15357.87	15386.9	15407.57	15417.76
2005	15344.06	15280.56	15301.5	15380.58	15358.22	15400.73

Year	NPI Base	Log-Log	1st Lag	2nd Lag	3rd Lag	ARIMAX
2006	15278.65	15211.83	15244.32	15202.35	15181.24	15256.83
2007	15339.9	15292.85	15236.83	15109.23	15086.13	15133.83
2008	15509.46	15467.46	15391.2	15375.38	15334.65	15369.31
2009	15672.73	15646.96	15615.0	15610.3	15593.17	15552.08
2010	15879.65	15840.46	15810.3	15810.79	15790.39	15773.79
2011	15986.01	15961.79	15961.57	15982.65	15975.08	15895.27
2012	16051.92	16042.62	16087.89	16084.77	16095.63	16030.73
2013	16094.19	16077.85	16035.82	15872.96	15934.76	15930.27
2014	16142.55	16112.34	16137.08	16156.38	16136.26	16059.96
2015	16079.5	16070.3	16156.75	16195.65	16212.99	16143.82
2016	15996.92	15950.78	16046.69	16115.5	16090.53	16115.61
2017	15978.49	15959.04	15912.72	15913.07	15916.57	15959.68
2018	15669.07	15671.88	15589.61	15550.98	15608.03	15599.60
2019	15165.1	15173.34	15157.14	15102.99	15125.49	15094.01
2020	15172.0	15172.0	15172.0	15172.0	15172.0	15150.56
2021	14670.98	14751.76	14799.36	14874.76	14826.3	14824.56
2022	14945.0	14945.0	14945.0	14945.0	14945.0	14945.0

H. Fitted Values For Small General Service Sales Model

Year	NPI Base	Exclude SS-GDP	Exclude 2.1 Customers	1st Lag	2nd Lag
1985	533724.3	529244.0	552554.3	-	-
1986	548162.4	543797.7	567425.8	545283.7	-
1987	567055.6	562928.9	586313.9	561611.5	565197.9
1988	584886.6	581370.1	601709.0	575779.9	578881.9
1989	612878.6	612737.8	618635.5	597219.0	599547.4
1990	618320.1	618263.5	623214.7	618391.5	620302.9
1991	623168.9	626516.5	612405.5	634789.8	636197.2

Year	NPI Base	Exclude SS-GDP	Exclude 2.1 Customers	1st Lag	2nd Lag
1992	622741.8	625973.3	610941.6	636006.7	635751.3
1993	624830.9	628127.5	613221.1	633786.7	633038.0
1994	632920.4	636515.8	620071.6	635126.4	634737.6
1995	631621.4	633332.2	626715.3	637569.9	637272.0
1996	634842.8	639629.5	618681.1	635028.5	634164.1
1997	645371.8	650907.3	625119.1	633928.9	633271.1
1998	655436.0	661606.8	631865.0	643305.0	643814.7
1999	653663.0	657083.1	640602.7	648863.1	649042.2
2000	663726.5	666338.8	654629.1	660126.9	660349.9
2001	667669.2	668610.3	666367.0	669907.0	669496.1
2002	671925.3	669414.7	684506.5	680293.7	679704.0
2003	678126.3	674530.8	694994.4	691239.5	690746.0
2004	683543.3	681693.7	691139.8	696689.3	696425.2
2005	696007.8	695112.1	697371.4	705681.6	705999.4
2006	697472.9	695068.2	703171.9	712132.2	712637.2
2007	705757.4	704459.8	707243.5	714818.2	714841.8
2008	720112.9	717804.7	726573.7	726703.1	726848.2
2009	732399.8	732124.9	729787.1	733348.1	733462.1
2010	746817.8	745441.5	749311.1	742194.6	741857.4
2011	756217.7	753163.6	764258.9	753128.0	753514.4
2012	773469.8	773148.9	767769.2	766709.4	768225.1
2013	783409.1	783534.5	776236.8	774996.4	775575.9

Year	NPI Base	Exclude SS-GDP	Exclude 2.1 Customers	1st Lag	2nd Lag
2014	796342.6	795580.2	795428.7	786157.2	785900.0
2015	800052.2	799535.9	798670.9	792895.4	792501.6
2016	807295.9	806621.8	809636.7	802558.9	801381.8
2017	810587.2	809857.6	815263.8	806021.5	804147.5
2018	806121.4	806518.0	804414.1	801985.7	801244.6
2019	793629.9	793055.4	795464.8	806825.9	807917.8
2020	752061.0	752061.0	752061.0	752061.0	752061.0
2021	763687.6	764347.7	762281.6	762190.0	762570.2
2022	784133.0	784133.0	784133.0	784133.0	784133.0