TIME OF USE RATES IN ONTARIO

PART 2: ALTERNATIVE SCENARIO ANALYSIS

Prepared for the

ONTARIO ENERGY BOARD

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Executive Summary

Under amendments to the Ontario Energy Board Act, 1998 (the Act) contained in the Electricity Restructuring Act, 2004, the Ontario Energy Board was mandated to develop a Regulated Price Plan (RPP) for electricity prices to be charged to consumers (with peak demands of less than 50 kW) that have been designated by regulation. The first prices were implemented under the RPP effective on April 1, 2005, as set out in regulation by the Ontario Government.

Since the May 2006 price setting, in addition to the RPP tiered rates, RPP customers have gradually been transitioned to time-of-use (TOU) rates. TOU rates have a three period (On-Peak, Mid-Peak, Off-Peak) two season (November through April, May through October) structure. It is anticipated that by the end of 2014 nearly all of Ontario's RPP customers will be converted from tiered to TOU rates. As of June 2013, nearly 4.5 million (approximately 93%) of Ontario's RPP-eligible customers were subject to TOU rates.[1] Ontario is the only jurisdiction in North America with universal mandatory TOU rates for residential and small general service (GS) customers.[2]

Navigant was engaged by the OEB in the spring of 2013 to undertake a two-part study of TOU rates.

Part 1: Estimate the historical impact of TOU rates on the consumption of a sample of customers drawn from participating local distribution companies (LDCs).

Part 2: Using the results of #1, forecast the impact, all else equal, of five alternative TOU structures (referred to below as "scenarios").

This report addresses Part 2 of the study. Navigant's report that addresses Part 1 of the study is available on the OEB website.

Scenarios, Evaluation Metrics and Informational Outputs

The scenarios analysed, the metrics used to evaluate them and the informational outputs were selected by Navigant based on feedback received from OEB staff.

Alternative TOU Rate Structures

Navigant analysed five alternative TOU rate structures. Each of these scenarios is analysed in contrast to the current rate structure, referred to as the Status Quo (SQ).

The rates generated for the scenarios were designed on the same cost-recovery basis as the current RPP price-setting approach. Prices are set such that forecast RPP revenues offset the forecast cost to

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1 As per OEB correspondence, approximately 95% of residential and 74% of general service RPP eligible customers were subject to TOU prices as of June 2013.

2 "Small general service" (GS) refers to those non-residential customers with peak demand of less than 50 kW.

serve RPP consumption, ignoring any customer behaviour changes that may occur in response to those rates.

The SQ prices and TOU periods are summarized in Figure ES - 1, below. This figure shows the weekday SQ TOU structure by season (far left column) across the 24 hours of a weekday. The rate for each TOU period is called out within the relevant band of colour. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am on non-holiday weekdays.

Figure ES - 1: SQ TOU Periods and Prices (Cents /kWh)

Scenario TOU Periods - Weekdays Only*																								
Hour Ending (EPT):	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer	6.7							10.4				12.4						10.4		6.7				
Summer Shoulder	6.7							10.4				12.4						10.4		6.7				
Winter	6.7							12.4				10.4						12.4		6.7				
Winter Shoulder	6.7							12.4				10.4						12.4		6.7				

Off-Peak Mid-Peak On-Peak

Weekend and holiday prices in each season are the same as weekday prices from 7pm to 7am (hour ending 20 to 7)

Source: OEB and Navigant analysis.

The five scenarios analyzed by Navigant are described below.

The CPP Scenario: Status Quo with CPP (Voluntary) – "CPP" scenario. Customers volunteering to pay a critical peak rate over four hours (2pm to 6pm) on up to 15 summer weekdays are subject to a discounted Off-Peak rate in the RPP summer months. In the RPP winter months, these customers are subject to Status Quo TOU prices. Navigant has assumed that 5% of residential RPP customers and 2.5% of GS RPP customers will participate in this rate.

The voluntary CPP Scenario weekday prices and TOU periods are summarized in Figure ES - 2, below. All coloured periods apply on every weekday of the season indicated whereas cross-hatched periods (i.e., critical peak periods) apply only on those days in which a critical peak event occurs. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am on non-holiday weekdays.

Figure ES - 2: The CPP Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><th>Hour Ending (EPT):</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer</td><td colspan="7">5.7</td><td colspan="4">10.4</td><td colspan="3">12.4</td><td colspan="3">(50)</td><td colspan="2">10.4</td><td colspan="5">5.7</td></tr>
<tr><td>Summer Shoulder</td><td colspan="7">5.7</td><td colspan="4">10.4</td><td colspan="6">12.4</td><td colspan="2">10.4</td><td colspan="5">5.7</td></tr>
<tr><td>Winter</td><td colspan="7">6.7</td><td colspan="4">12.4</td><td colspan="6">10.4</td><td colspan="2">12.4</td><td colspan="5">6.7</td></tr>
<tr><td>Winter Shoulder</td><td colspan="7">6.7</td><td colspan="4">12.4</td><td colspan="6">10.4</td><td colspan="2">12.4</td><td colspan="5">6.7</td></tr>
</table>

Off-Peak | Mid-Peak | On-Peak

Critical Peak (15 days for Scenario 1, 5 days for Scenario 4)

Weekend and holiday prices in each season are the same as weekday prices from 7pm to 7am (hour ending 20 to 7)

Source: OEB and Navigant analysis.

2: Two Prices Winter/Summer, One Price Shoulder (Mandatory) – "Flat" scenario. Under this scenario, the new prices and TOU periods are assumed to apply to all RPP customers. In the winter and summer months, customers are subject to an On-Peak rate from 7am to 7pm on weekdays and an Off-Peak rate the rest of the time. In the shoulder months, customers are subject to a single rate in all hours.

The mandatory Flat Scenario weekday prices and TOU periods are summarized inFigure ES - 3, below. Weekends and holidays in the summer and winter are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am on non-holiday weekdays.

Figure ES - 3: The Flat Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><th>Hour Ending (EPT):</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer</td><td colspan="7">6</td><td colspan="12">15</td><td colspan="5">6</td></tr>
<tr><td>Summer Shoulder</td><td colspan="24">9</td></tr>
<tr><td>Winter</td><td colspan="7">6</td><td colspan="12">15</td><td colspan="5">6</td></tr>
<tr><td>Winter Shoulder</td><td colspan="24">9</td></tr>
</table>

Off-Peak | On-Peak | Shoulder

Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)

Source: OEB and Navigant analysis.

Scenario 3: Summer Super-Peak (Mandatory) – "Super-Peak" scenario. Under this scenario, the new prices and TOU periods are assumed to apply to all RPP customers. From September through May, customers are subject to an On-Peak rate from 7am to 7pm on weekdays and an Off-Peak rate the rest of the time. From June through August, on weekdays customers are subject to an On-Peak rate from

7am to 1pm, a Super-Peak rate from 1pm to 7pm and an Off-Peak rate at all other times including weekends.

The mandatory Super-Peak Scenario weekday prices and TOU periods are summarized in Figure ES - 4, below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am on non-holiday weekdays.

Figure ES - 4: The Super-Peak Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><th>Hour Ending (EPT):</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer</td><td colspan="7">6.7</td><td colspan="6">8.7</td><td colspan="6">32.4</td><td colspan="5">6.7</td></tr>
<tr><td>Summer Shoulder</td><td colspan="7">6.7</td><td colspan="12">8.7</td><td colspan="5">6.7</td></tr>
<tr><td>Winter</td><td colspan="7">6.7</td><td colspan="12">8.7</td><td colspan="5">6.7</td></tr>
<tr><td>Winter Shoulder</td><td colspan="7">6.7</td><td colspan="12">8.7</td><td colspan="5">6.7</td></tr>
</table>

Off-Peak Mid-Peak On-Peak Super-Peak

****Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)***

Source: OEB and Navigant analysis.

Scenario 4: Status Quo with Critical Peak Days (Voluntary) – "CPD" scenario. RPP customers volunteering to participate in this rate pay a critical peak rate over 12 hours (10am to 10pm) on five summer weekdays, and are subject to a discounted On-Peak and Mid-Peak rate in the RPP summer months. In the RPP winter months, these customers are subject to Status Quo TOU prices. Navigant has assumed that 5% of residential RPP customers and 2.5% of GS RPP customers will participate in this rate.

The voluntary CPD Scenario weekday prices and TOU periods are summarized in Figure ES - 5, below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am on non-holiday, non-CPD weekdays.

Figure ES - 5: The CPD Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><th>Hour Ending (EPT):</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer</td><td colspan="7">6.7</td><td colspan="4">9.3</td><td colspan="6">11.1 (30)</td><td colspan="2">9.3</td><td colspan="5">6.7</td></tr>
<tr><td>Summer Shoulder</td><td colspan="7">6.7</td><td colspan="4">9.3</td><td colspan="6">11.1</td><td colspan="2">9.3</td><td colspan="5">6.7</td></tr>
<tr><td>Winter</td><td colspan="7">6.7</td><td colspan="4">12.4</td><td colspan="6">10.4</td><td colspan="2">12.4</td><td colspan="5">6.7</td></tr>
<tr><td>Winter Shoulder</td><td colspan="7">6.7</td><td colspan="4">12.4</td><td colspan="6">10.4</td><td colspan="2">12.4</td><td colspan="5">6.7</td></tr>
</table>

Off-Peak Mid-Peak On-Peak
Critical Peak (15 days for Scenario 1, 5 days for Scenario 4)

****Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)***

Source: OEB and Navigant analysis.

Scenario 5: Enhanced Status Quo – "ESQ" scenario. Under this scenario, the new prices and TOU periods are assumed to apply to all RPP customers. All TOU periods are identical to those in the Status Quo, only the prices are different.

The mandatory ESQ Scenario weekday prices and TOU periods are summarized in , below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am on non-holiday weekdays.

Figure ES - 6: The ESQ Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><td>Hour Ending (EPT):</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer</td><td colspan="7">4.6</td><td colspan="4">13.7</td><td colspan="6">18.2</td><td colspan="2">13.7</td><td colspan="5">4.6</td></tr>
<tr><td>Summer Shoulder</td><td colspan="7">4.6</td><td colspan="4">13.7</td><td colspan="6">18.2</td><td colspan="2">13.7</td><td colspan="5">4.6</td></tr>
<tr><td>Winter</td><td colspan="7">4.6</td><td colspan="4">18.2</td><td colspan="6">13.7</td><td colspan="2">18.2</td><td colspan="5">4.6</td></tr>
<tr><td>Winter Shoulder</td><td colspan="7">4.6</td><td colspan="4">18.2</td><td colspan="6">13.7</td><td colspan="2">18.2</td><td colspan="5">4.6</td></tr>
</table>

Off-Peak Mid-Peak On-Peak

****Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)***

Source: OEB and Navigant analysis.

Evaluation Metrics

Navigant, with input from the OEB, established three quantitative and one qualitative metrics to assist in the ranking of each scenario. The four metrics are described below.

Impact on System Peak Demand (Quantitative): the degree to which the given scenario reduces Ontario system peak demand. Navigant has calculated system peak demand as the average IESO Ontario demand during the ten highest system demand hours of the year[3], consistent with the method applied by the Ontario Power Authority (OPA) for calculating that agency's "CF2" peak coincidence factor.[4]

Ease of Implementation (Qualitative): the ease with which the given scenario could be implemented. This metric considers factors such as the technical feasibility of each scenario (i.e., the ability of billing systems to implement it), the degree to which each scenario would likely be accepted by the public and the legal and regulatory implications of each scenario.

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3 Note that this metric does not measure the impact on demand on the ten hours of the year that experienced highest demand in the Status Quo, but rather the difference between the average demand in those hours and the average demand in the "new" top ten hours of the given scenario.

4 The OPA's "CF2" peak coincidence factor is a parameter estimated by the OPA for conservation measures and programs, and is intended to quantify the degree to which measure or program savings are coincident with system peak. More detail may be found in Appendix A of: Ontario Power Authority, *Prescriptive Measures and Assumptions: Release Version 1*, March 2011

Alignment with System Marginal Costs (Quantitative): the degree to which the given scenario's prices reflect the variation in actual short-term system marginal costs, as represented by the wholesale Hourly Ontario Energy Price (HOEP).

Price Stability (Quantitative): the degree to which under- or over-recovery of RPP supply cost (and thus the variance that would need to be collected in the next price-setting) that results from a given scenario potentially increases the volatility of RPP TOU prices.

When considering the overall "performance" of a scenario, these metrics are given equal weight. Navigant recognizes that stakeholders are likely to have different views on the relative importance of each metric.

Informational Outputs

Navigant also provided two "informational outputs". These outputs are distinct from the evaluation metrics in that they are not used to gauge the desireability or performance of the scenarios, but rather to provide policy-makers and analysts a more nuanced understanding of the impacts of each scenario. The two informational outputs are described below.

Unit Cost Impacts by Customer Type. The "unit cost impact" is the estimated percentage change in how much a given customer type pays, on average, for each kWh of consumption – the sum of commodity (i.e., TOU rate) and non-commodity volumetric costs.

Changes in Energy Consumption. The estimated change in annual energy consumption (GWh) relative to the SQ due to the given scenario.Scenario Price Setting and Behavioural Impact Methods

This section of the executive summary outlines the approaches used by Navigant to model prices and scenarios.

Test Years

To reflect the natural variation of electricity demand, Navigant has used two test years as the basis for its analysis, 2011 and 2012. Data from the test years were combined with forecast system costs, RPP and system energy consumption from the May 1, 2013 RPP price setting to set the prices for each scenario and establish status quo levels of demand for the two RPP customer classes and for the Ontario system as a whole.

Thus the *relative* system costs and consumption levels (i.e., the cost and consumption *profiles*) used in the modeling reflect the fluctuations and variations observed in 2011 and 2012, but the *absolute* system costs and consumption levels (i.e., the forecast monthly or annual values) reflect those forecast as part of the May 2013 RPP price setting.

Scenario Price Setting

The approach to setting TOU prices varies by scenario, but for all scenarios prices were set to ensure total cost recovery in each test year, given:

- the underlying commodity price (i.e., HOEP),
- Status Quo consumption profiles,
- the RPP May 2013 forecast absolute level of RPP consumption, and
- the RPP May 2013 forecast of total system costs.

Navigant's price-setting does not iterate the set price based on estimated behaviour changes – prices are set assuming Status Quo levels and timing of consumption. That is, the prices are set such that forecast consumption (absent behaviour changes due to alternative scenarios) will recover forecast system costs. This is consistent with how the RPP TOU prices are set today.

Price-setting details by scenario may be found in chapter 3 of the report, below.

Scenario Behavioural Impact Calculation

Average customer behavioural impacts – i.e. the change in the consumption profile due to the change in prices between the SQ and each scenario, for residential customers, are estimated based entirely on the own- and cross-price elasticities estimated in Part 1 of this study.

General service (GS) customer behavioural impacts[5] are estimated based on an own-price elasticity only. This own-price elasticity was estimated based on the residential own-price elasticities estimated in Part 1 of this study and the assumption that GS customers will tend to be less price-sensitive (in the short to medium term) to fluctuations in electricity prices than residential customers.

This approach was required because Navigant does not believe that the GS elasticities estimated in Part 1 of this study are sufficiently robust to support the scenario analysis.

Behavioural Impacts, Evaluation Metric and Informational Impact Results

Behavioural Impacts

In most cases, behavioural impacts were as expected; consumption fell in periods that were relatively more expensive than the Status Quo, and increased in periods that were less expensive than the Status Quo.

For example, Figure ES - 7, below shows the estimated impact of critical peak prices on an average residential customer. As expected, very high prices during the Critical Peak period result in consumption being shifted to other, less expensive periods.

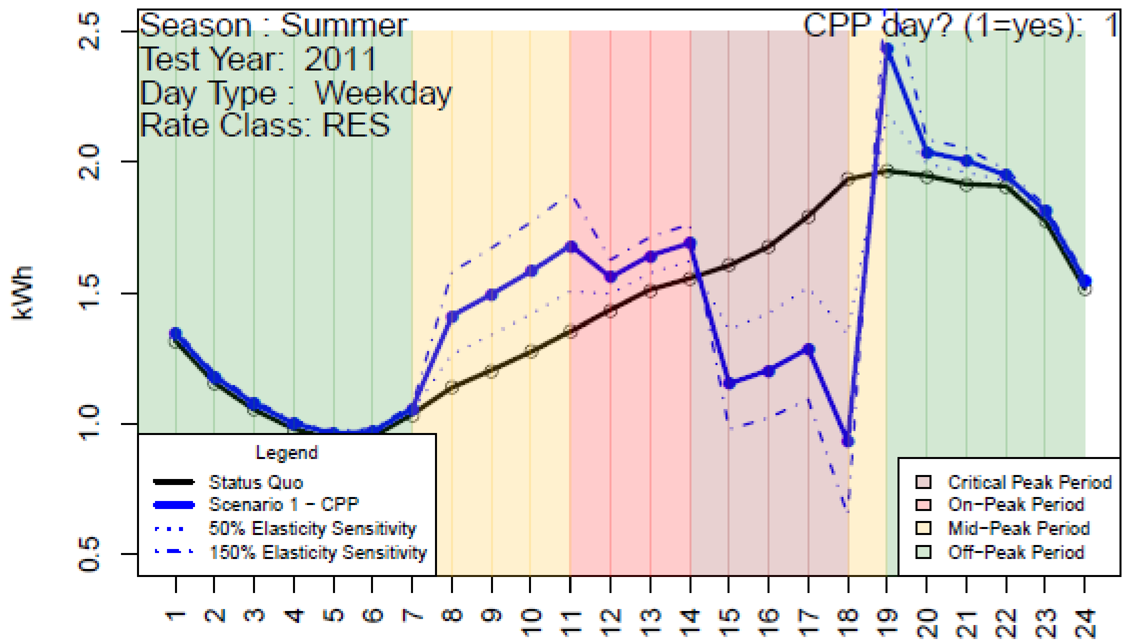
In this plot and those that follow, the black line represents the Status Quo average consumption per customer and the blue line represents the estimated average consumption per customer subject to that scenario's new price and period structure. Estimated average consumption per customer when

[5] As with the RPP, this analysis applies only to general service customers with less than 50 kW of peak demand.

elasticities are 50% of those estimated is represented by the narrow dotted line, and estimated average consumption per customer when elasticities are 150% of those estimated is represented by the narrow dash-dotted line. These are included only to illustrate the sensitivity of the results to the estimated elasticities.

The given scenario's different price periods are represented by the differently coloured columns.

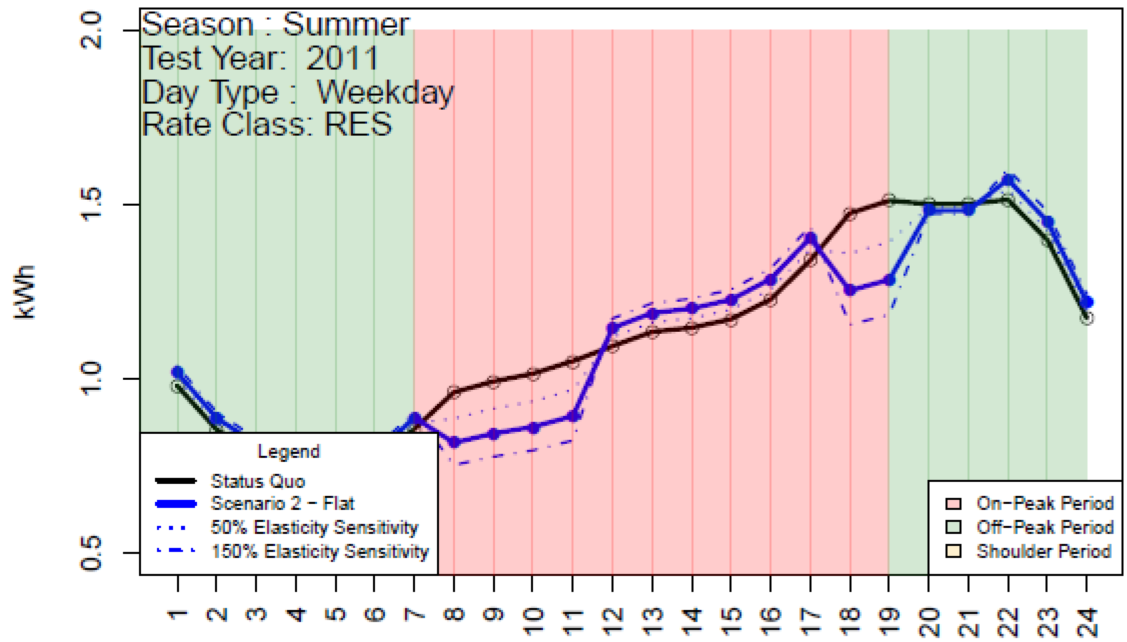
Figure ES - 7: CPP Scenario, Average Summer CPP Day Residential Profile



Source: OEB-provided hourly consumption data and Navigant analysis

In some cases, such as for the Flat Scenario (see Figure ES - 8 below), the impact may initially appear to be counter-intuitive, but in fact makes sense given relative price changes and the elasticities estimated in Part 1 of this study.

Figure ES - 8: Flat Scenario, Average Summer Weekday Residential Profile

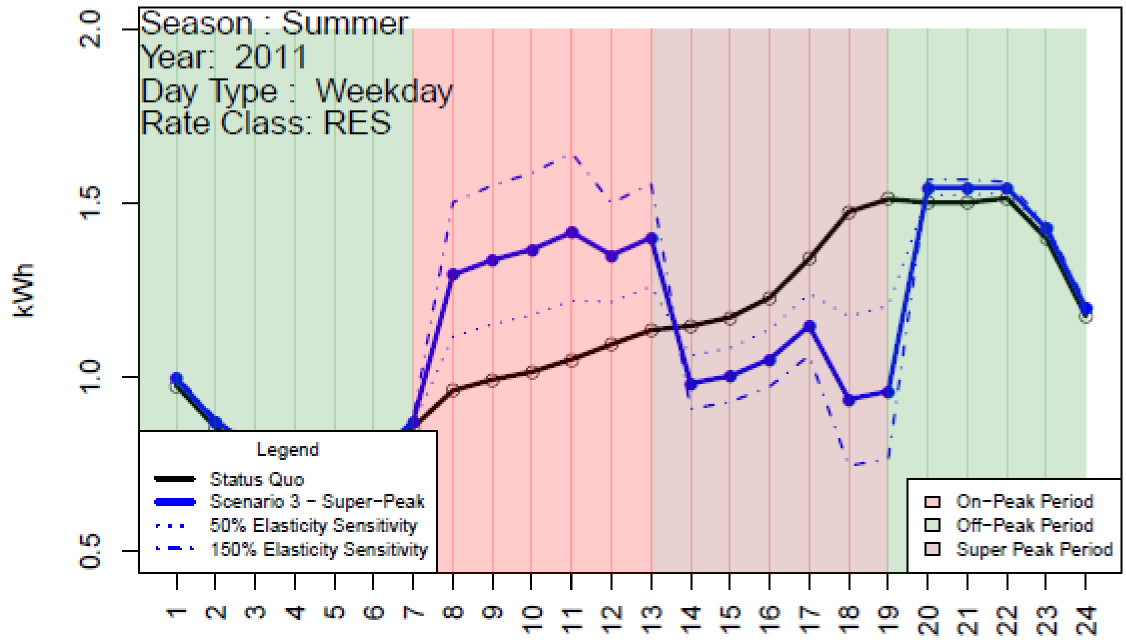


Source: OEB-provided hourly consumption data and Navigant analysis

Consumption increases in the middle of the day (the Status Quo On-Peak, 11am to 5pm) even though prices have increased in that period (from 12.4 cents/kWh to 15 cents/kWh) because prices have increased *even more* in the morning and early evening (Status Quo Mid-Peak period, 7am to 11am and 5pm to 7pm), making the middle of the day (Status Quo On-Peak) *relatively* if not absolutely cheaper than in the Status Quo.

As with the CPP Scenario, the Super-Peak Scenario exhibits estimated changes in consumption that are all in the expected direction. In the period in which prices have greatly increased (the Super-Peak from 1pm to 7pm) consumption has fallen, and in the period in which prices have fallen (the scenario-specific On-Peak, from 7am to 1pm) consumption has increased (see Figure ES - 9).

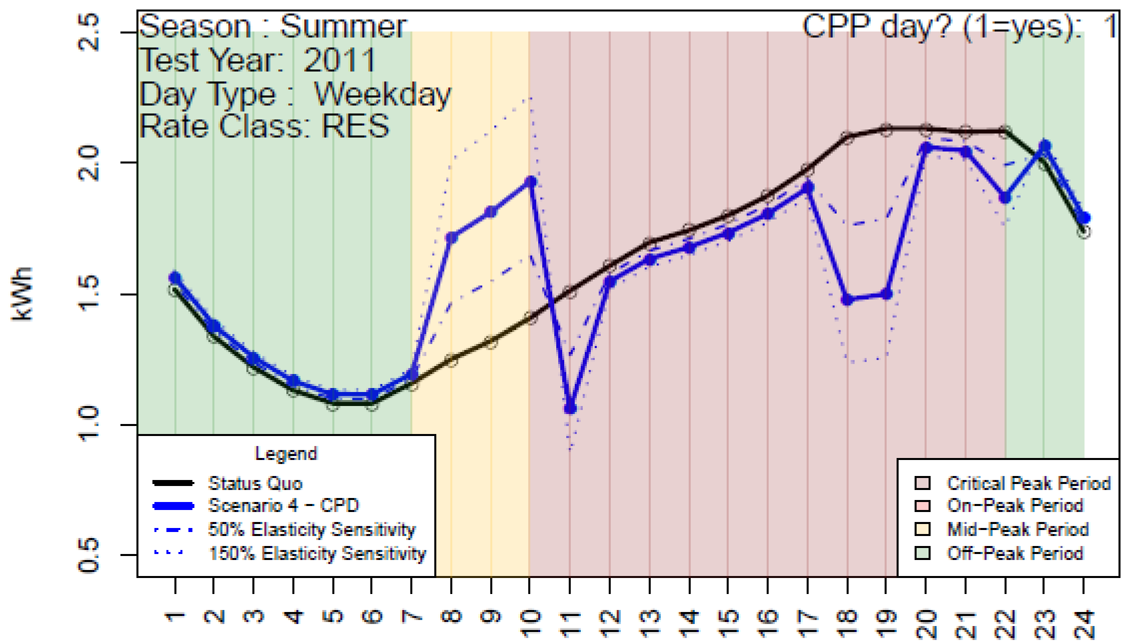
Figure ES - 9: Super-Peak Scenario, Average Summer Weekday Residential Profile



Source: OEB-provided hourly consumption data and Navigant analysis

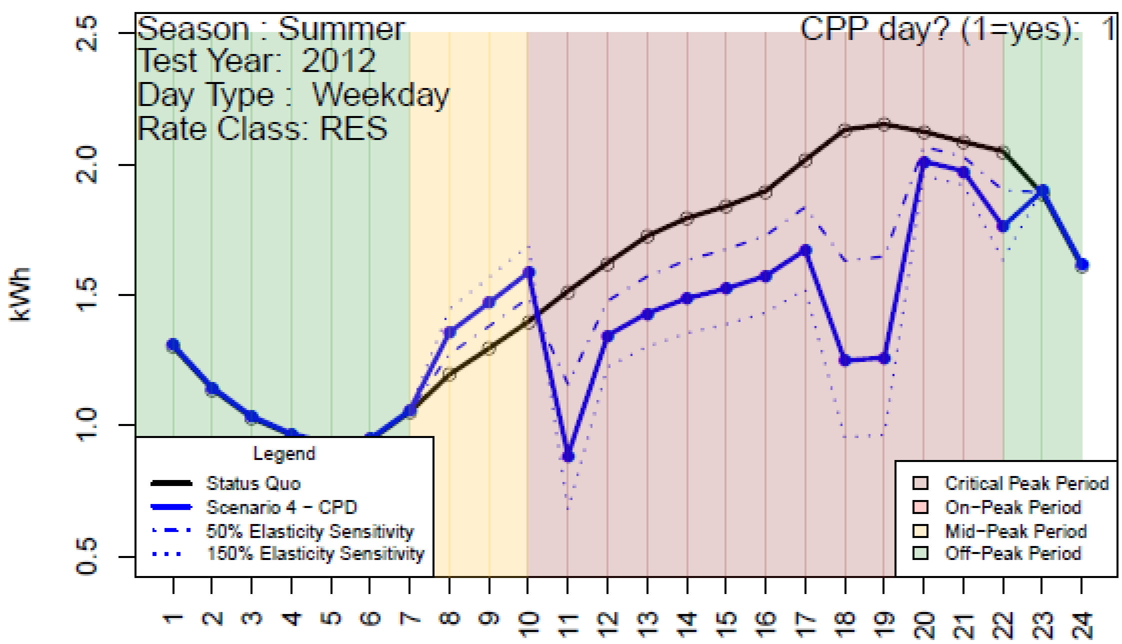
In evaluating the impact of the CPP and CPD Scenarios, Navigant also found that the clustering of events can significantly impact the effectiveness of the critical peak price signal. Recall that the CPD scenario applies a critical peak price to participating customers from 10am to 10pm on five days of the summer. To be most effective, it was assumed that the five days so targeted would also be the top five demand days of the summer. In test year 2011, all five of the top five demand days occurred in a single week (July 18 – July 22, 2011). The impact on the effectiveness may be judged by comparing Figure ES - 10, which shows the impact of the CPD Scenario prices on an average participant in test year 2011 (when all five events were clustered in a single week) with Figure ES - 11 which shows the impact of CPD Scenario prices on an average participant in test year 2012 (when there were at most two events in any given week).

Figure ES - 10: CPD Scenario, Average Summer CPD Day Residential Profile – Test Year 2011



Source: OEB-provided hourly consumption data and Navigant analysis

Figure ES - 11: CPD Scenario, Average Summer CPD Day Residential Profile – Test Year 2012

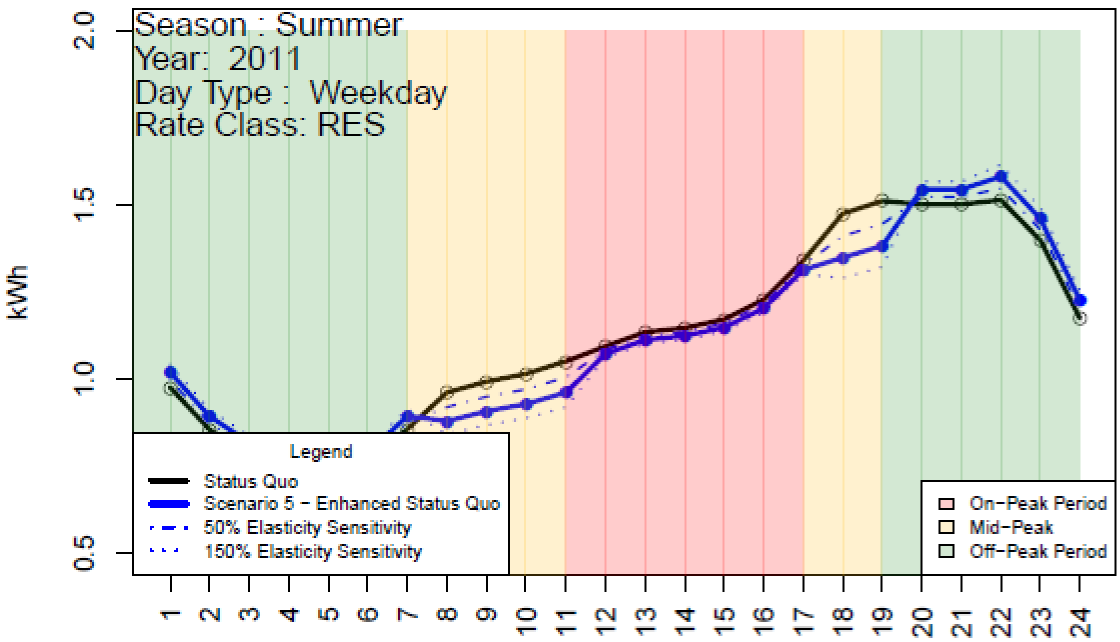


Source: OEB-provided hourly consumption data and Navigant analysis

When every day of a week is a critical peak event, there are simply fewer periods within that week to which critical peak period consumption can be shifted. As a result the behavioural response to the critical peak price is muted.

Like the Flat Scenario, the ESQ Scenario raised the price of electricity in all summer hours between 7am and 7pm. Unlike the Flat Scenario, however, the ESQ Scenario did not result in an unanticipated increase in consumption from 11am to 5pm, as is evident from Figure ES - 12, below.

Figure ES - 12: The ESQ Scenario Residential Summer Critical Peak Day Profile – Test Year 2011



Source: OEB-provided hourly consumption data and Navigant analysis

The ESQ Scenario avoids delivering an unanticipated increase in consumption from 11am to 5pm, by maintaining a differential between the 11am to 5pm price period and the 7am to 11am and 5pm to 7pm time period. This effectively discourages customers from shifting Mid-Peak consumption into the On-Peak period, as occurred in the Flat Scenario.

It should be noted that the estimated behaviour changes above are driven by elasticities estimated using historical data with only mild price variation. Likewise the overall conservation effect was estimated using data where price increases over time were relatively small. These estimated relationships between price and demand in the different periods may not accurately characterize customer behaviour when price differentials and cost increases are very high and well outside the bounds of what has been observed historically.

Evaluation Metric Results

A summary of the ranking of each scenario against all evaluation metrics is summarized in Figure ES - 22, below. The lower the rank, the more "desirable" the scenario – for a given metric a rank of 1 indicates the "best" scenario, and a rank of 4, the "worst".

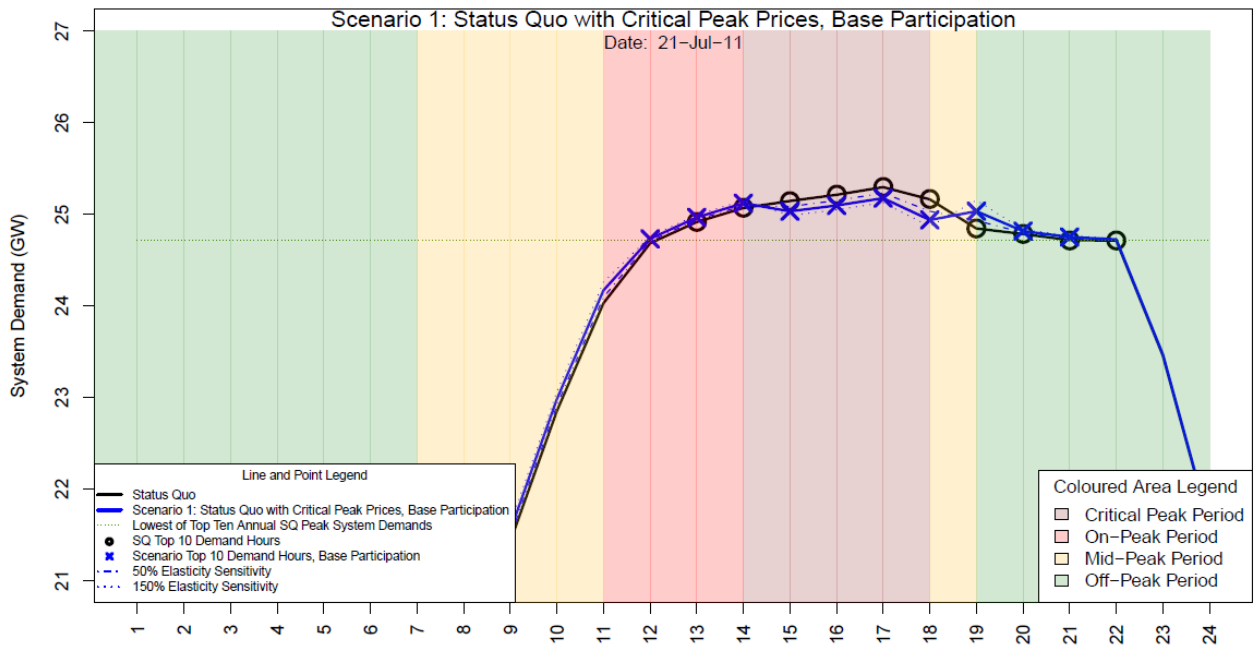
Peak System Demand Impact Metric

Peak System Demand Impact Metric

One of the most important observations made as part of this analysis by Navigant is that in both test years, the IESO system demand on the peak demand day of the summer is relatively flat – it is a plateau, and not a summit. This is readily apparent in Figure ES - 13, below.

In this plot (and those that follow, discussing system peak demand impacts), the black line shows the Status Quo Ontario system demand on the peak demand day in 2011 (July 21) and the blue line shows the estimated Ontario system demand under the CPP Scenario. The markers (crosses and circles) indicate whether an hour is a top ten annual system demand hour for the scenario and the Status Quo, respectively. Note that shifting in response to the critical peak period leads to an increase in system peak demand in the hours immediately preceding and following the critical peak period. Recall that the CPP Scenario is assumed to be voluntary with a 5% participation rate.

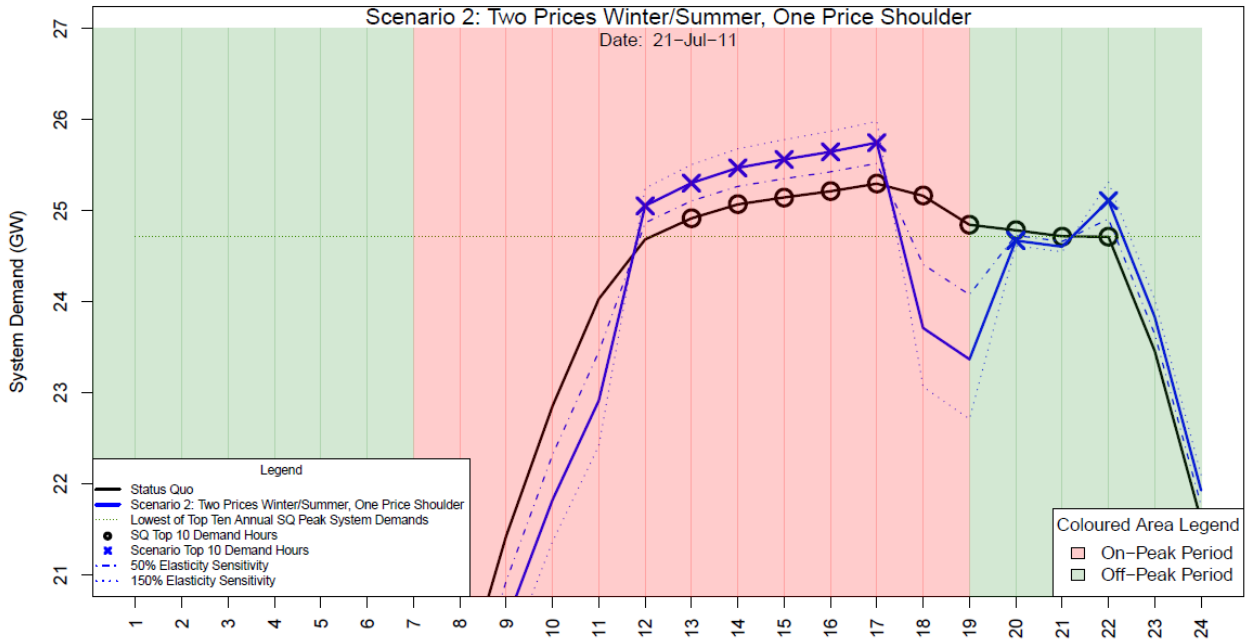
Figure ES - 13: System Peak Demand Impact, CPP Scenario



Source: IESO, OEB, OEB-provided hourly consumption data and Navigant analysis

Figure ES - 14, below shows the system peak demand impact of the mandatory Flat Scenario structure. In this case prices increase in the Status Quo On-Peak period (11am – 5pm) due to the relative price changes and demand shifting effects noted above in relation to Figure ES - 8.

Figure ES - 14: System Peak Demand Impact, Flat Scenario



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The flatness of the system peak, and the behavioural changes implied by the estimated elasticities can lead to apparently counter-intuitive effects – for example, the mandatory Super-Peak Scenario as modeled leads to a significant *increase* in IESO system peak demand due to residential demand shifting (see Figure ES - **15**).

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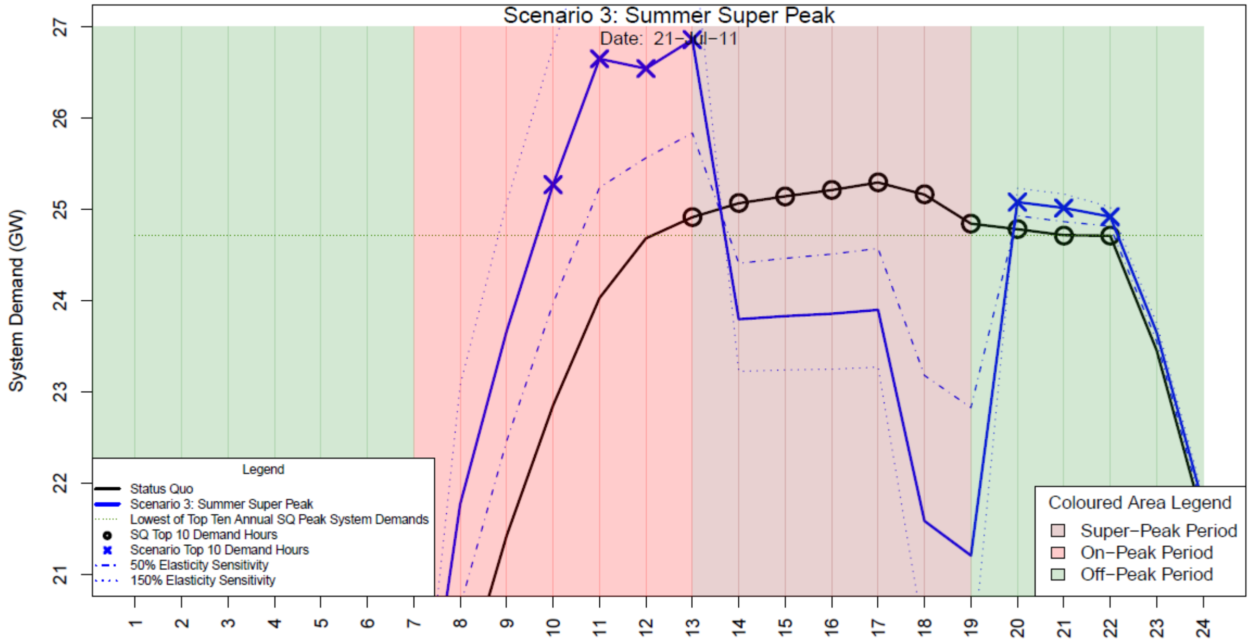
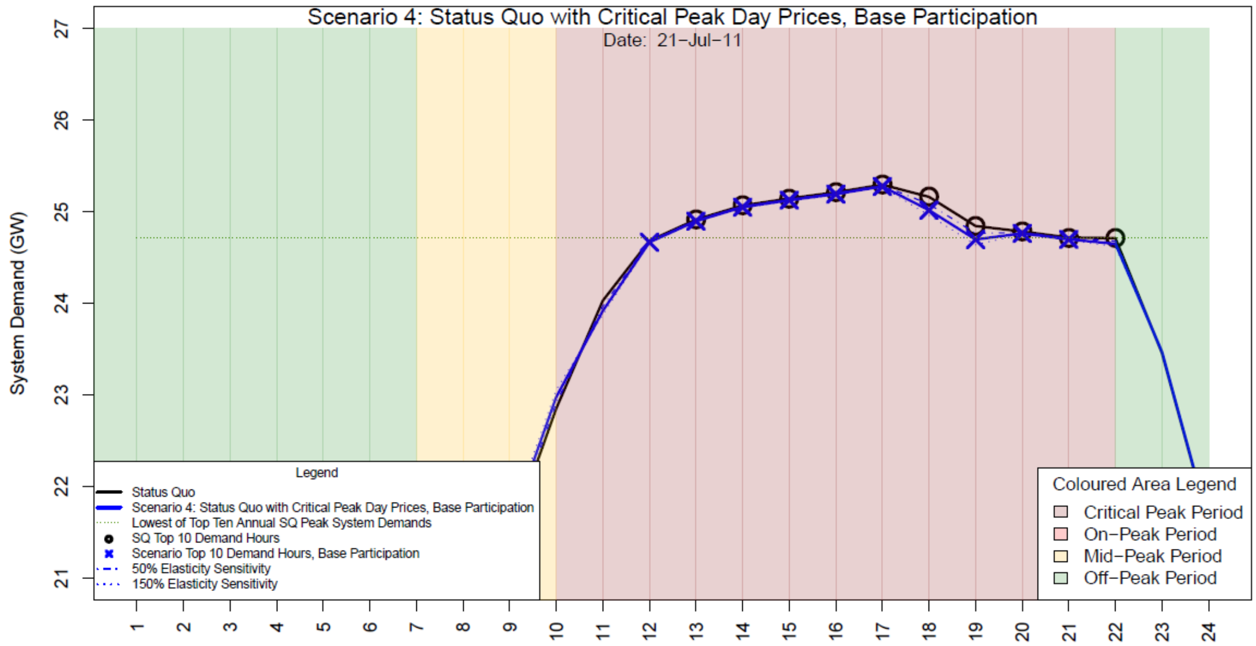
Figure ES - 15: System Peak Demand Impact, Super-Peak Scenario



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

As may be seen in Figure ES - 16, below, the CPD Scenario in 2011 yields relatively small demand reductions in any given hour (due in part to assumptions regarding the participation rate and the clustering effect noted above). This scenario, however, does not result in an increase in system peak demand (compared to the Status Quo) in the hours adjacent to the critical peak period (10am – 10pm). As a result, this scenario yields the largest system peak demand reductions of any of the scenarios examined.

Figure ES - 16: System Peak Demand Impact, CPD Scenario



Source: IESO, OEB, OEB-provided hourly consumption data and Navigant analysis

It is immediately clear when examining Figure ES - 17 that the impact of the ESQ Scenario is to reduce demand materially during the majority of the system peak demand hours on the "plateau". Like all the other scenarios, with the exception of the CPD Scenario, the fact that the periods of elevated prices (On-Peak and Mid-Peak periods) do not cover all of the system peak hours in the evening leads to some "take back" of peak demand impacts. That is, the demand reductions realized from 11am to 7pm are partially offset by demand increases from 7pm to 10pm.

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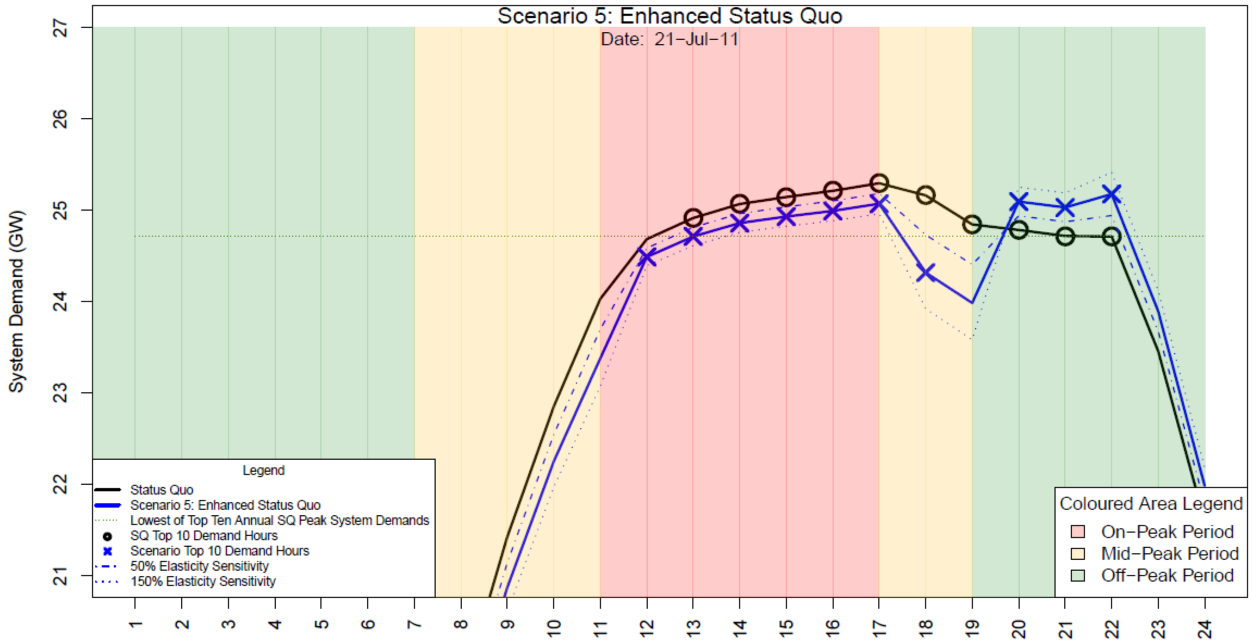
Figure ES - 17: System Peak Demand Impact, ESQ Scenario



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

System peak demand impacts, relative to the Status Quo, are summarized by test year, and an average across both test years in Figure ES - 18, below. In this table, a negative number indicates an estimated reduction in system peak demand and a positive number indicates an increase in system peak demand.

Figure ES - 18: System Peak Demand Impact (MW)

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	-20	197	464	-47	-118
2012	-58	229	619	-99	-218
Average	**-39**	**213**	**542**	**-73**	**-168**
Rank:	**3**	**4**	**5**	**2**	**1**

NB: assumes 5% residential and 2.5% GS participation for the CPD and CPP Scenarios

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The CPP and CPD Scenarios both result in a net reduction in system peak demand, although this varies significantly by test year. This variance is due to the clustering of critical peak events noted above. The relatively moderate impact of these two scenarios is also driven by the assumed participation rate: 5% of residential RPP customers and 2.5% of GS RPP customers for both scenarios.

The Flat Scenario, as would be expected given the result shown in Figure ES - 8, above, increases system peak demand since the *relative* (not absolute) price reduction in the Status Quo On-Peak period results in a moderate increase in consumption in that period.

The Super-Peak Scenario actually *increases* system peak demand across both test years by an average of over 500 MW. This increase is driven by three factors:

1. the rate is mandatory and applied to all RPP customers;

2. the combined effect of a significant price increase from 1pm to 7pm (Scenario 3 price: ~30 cents/kWh) and a considerable price decrease from 7am to 1pm (Scenario 3 price: ~ 9 cents/kWh); and

3. that system peak demand observed in 2011 and 2012 resembles a plateau and not a summit.

The ESQ Scenario results in the largest system peak demand reduction of all the scenarios modeled. This is due to three factors:

1. prices are raised over a long period (7am to 7pm) and so cover the majority of the peak demand "plateau";
2. prices in the Mid-Peak and On-Peak periods are increased by similar proportions so as not to provoke unanticipated and undesireable mid-day increases in consumption (as in the Flat Scenario).
3. unlike the CPP and CPD Scenarios, this is a mandatory structure with 100% of RPP customers assumed to participate.

It is important to bear in mind that although the ESQ Scenario delivers a larger peak demand reduction than the CPD Scenario in absolute terms, when normalized for participation, the CPD Scenario's peak demand reduction is larger. For example, if participation were four times the anticipated base level (i.e., 20% of the population participated in the CPD program) then the peak demand reduction for the CPD Scenario would be approximately 250 MW, more than that achieved by the ESQ Scenario when 100% of the population is participating.

Ease of Implementation Metric

Navigant has identified three distinct aspects of implementation that define each scenario's overall ease of implementation.

Technical Feasibility. The expected relative ease (or difficulty) of implementation of each new structure for the MDM/R[6] and for LDC billing systems.

Public Acceptance. The expected opposition (or lack thereof) that the rate-paying public would have to each of the scenarios.

[6] The Meter Data Management and Repository (MDM/R) is operated by the Smart Meter Entity (SME) and processes smart meter consumption data to support Ontario's TOU implementation. The MDM/R processes the raw data provided by LDCs and outputs individual consumption quantities by TOU period for customer billing.

Legal/Regulatory. The expected degree to which legislation, regulation or OEB rules would need to change in order to allow the implementation of each of the scenarios.

Each scenario is assigned a rank for each of these aspects of implementation. The final rank assigned to each scenario is based on the average of each scenario's aspect-specific ranks. The overall metric rank for each scenario, as well as the rank for each aspect of implementation is shown in Figure ES - 19, below. As may be seen in this table, Navigant believes that the ESQ Scenario would prove to be the easiest of the scenarios to implement on the provincial level and that the Super-Peak and CPD Scenarios would be the most difficult. The poor performance on this metric is due to public resistance to a daily period with very high prices (the Super-Peak Scenario) and to the possibility that implementing the CPD structure might require changing legislation which currently requires an Off-Peak period from 7pm to 7am. Note that for some implementation aspects, different scenarios may have the same rank where Navigant believes that the difficulty in implementing the two scenarios would not be significantly different.

This metric is qualitative; it is based on Navigant's professional judgement and its interpretation of the relevant legislation, regulation and rules. A complete legal and regulatory analysis of each of the five scenarios is beyond the scope of this study, and Navigant's discussion should be understood to be a high level interpretation of the issues.

Figure ES - 19: Overall Ranking of Ease of Implementation and by Aspect of Implementation

Implementation Aspect	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Technical Feasibility	4	2	3	4	1
Public Acceptance	1	2	4	1	3
Legal/ Regulatory	1	3	2	4	1
Average Rank	**2**	**3**	**4**	**4**	**1**

Source: Navigant analysis

Alignment with System Costs Metric

The relative alignment of each scenario's prices with system costs was estimated by calculating the Euclidian[7] distance between the normalized average weekday prices in each scenario and the normalized average weekday marginal system cost (represented by the HOEP) in each hour. The scenario with the shortest Euclidean distance was determined to be the most closely aligned with

[7] The Eulidean distance between two points is a measure of the absolute distance between two points. This approach is equivalent to one making use of the sum of squared differences or the mean absolute deviation between two series.

system costs, and that with the farthest was determined to be the least closely aligned with system costs. The ranking of each scenario for each test year is shown in Figure ES - **20**.

Figure ES - 20: Ranking of Scenarios by Alignment with System Costs

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	3	2	4	1	5
2012	3	2	4	1	5
Overall Rank	**3**	**2**	**4**	**1**	**5**

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Price Stability Metric

The price stability is calculated as the difference between the forecast supply cost and the forecast RPP revenue collected under each scenario. A higher variance (in absolute terms) means less price stability since that variance will necessarily have to be collected in the following year.

All five scenarios are estimated to over-recover relative to the Status Quo. On average, however, the CPD Scenario over-recovers the least relative to the Status Quo. The fact that the variance is lowest for the CPP Scenario and the CPD Scenario is principally due to the assumed participation rate – 5% for residential customers and 2.5% for GS customers.

Figure ES - **21**, shows, in millions of dollars, how much each scenario over-recovers relative to the Status Quo. Two things are important to bear in mind when evaluating this result: firstly, as a percent of total RPP supply cost (approximately $4.5 billion/year) these variances are trivial. Secondly, these variances are due entirely to the fact that prices are set not anticipating behaviour changes. An iterative price-setting procedure that accounted for behaviour changes could considerably reduce these (already relatively small) variances.

Figure ES - 21: Variance Between RPP Revenue and System Costs (million $)

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	$0.4	$118.8	$46.9	$0.5	$105.5
2012	$0.6	$149.9	$96.4	$0.5	$133.6
Average	**$0.5**	**$134.4**	**$71.7**	**$0.5**	**$119.6**
Rank:	**2**	**5**	**3**	**1**	**4**

Source: IESO, OEB, OEB-provided hourly consumption data and Navigant analysis

Summary of Metric Rankings.

The ranking of each scenario against all four evaluation metrics is summarized in Figure ES - 22, below. The lower the rank, the more "desirable" the scenario – for a given metric a rank of 1 indicates the "best" scenario, and a rank of 5, the "worst".

This overall ranking is based simply on an unweighted average of the four metric rankings. Were weights to be assigned the overall result would likely be different.

Figure ES - 22: Summary of Ranking by Metric and Scenario

Metric	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Peak System Demand Impact	3	4	5	2	1
Alignment With System Costs	3	2	4	1	5
Ease of Implementation	2	3	4	4	1
Price Stability	2	5	3	1	4
Overall Average (Unweighted) Rank	**2**	**4**	**5**	**1**	**3**

Source: Navigant analysis

The highest ranked scenario overall is the CPD Scenario. It delivers the second-highest estimated system peak demand impacts, is the scenario most closely aligned with system costs and is also the scenario that delivers the most price stability, relative to the Status Quo. Unfortunately it is also the scenario that Navigant believes could be the most difficult to implement.

Informational Outputs

Unit Cost Impacts

Figure ES - **23** shows the average unit cost impact of each scenario on an "average" residential customer (i.e., a customer with the average load profile). The unit cost impact is defined as the percentage change in the average customer unit cost of electricity, i.e., the average change in the total variable cost of energy ($/ kWh). This variable cost includes both the commodity cost (the RPP price) and the non-commodity volumetric charges (i.e., distribution charges).

Two sets of unit cost impact are shown: the impact if the customer does not respond to the scenario prices (i.e., no change to the load profile from Status Quo) and the impact if the customer responds to the scenario prices as suggested by the estimated elasticities. A positive number indicates an increase in the unit cost of electricity, a negative number indicates a decrease in the unit cost. For reference, the annual variable cost of electricity for an average residential customer is approximately $1,200.

Figure ES - 23: Average Residential Customer Unit Cost Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	1%	2%	3%	0%	1%
2012	1%	3%	3%	1%	2%
Average	**1%**	**2%**	**3%**	**0%**	**2%**
Price Response as Modeled by Elasticities					
2011	0%	2%	0%	0%	0%
2012	0%	2%	1%	0%	1%
Average	**0%**	**2%**	**1%**	**0%**	**0%**

Source: OEB-provided hourly consumption data and Navigant analysis

With no change in behaviour, all five scenarios result in the average residential customer facing a higher unit cost for electricity. Once changes in behaviour are taken into account, an average residential customer under the CPP, CPD or ESQ Scenarios is estimated to have a unit cost no different than under the Status Quo. These percentages may be applied to the average annual cost cited above, so, for example, after taking into account behaviour changes, the Super-Peak Scenario is estimated to increase the variable cost of electricity for an average residential customer by approximately $12 per year.

Changes in Energy Consumption

Figure ES - 24 shows the impact of each scenario on energy consumption (GWh/year) in each of the two test years for residential customers. A negative number in this table indicates a reduction in energy consumption and a positive number indicates an increase. The only scenario that results in energy conservation is the Flat Scenario. All other scenarios, due to the discounts they offer to entice customers to consume in non-peak periods, increase total energy consumption.

Figure ES - 24: Residential Energy Impact (GWh/Year) by Scenario

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	9.7	-48.1	346.0	1.2	268.9
2012	9.6	-37.3	261.0	2.2	247.6
Average	**9.7**	**-42.7**	**303.5**	**1.7**	**258.2**

Source: OEB-provided hourly consumption data and Navigant analysis

Observations and Considerations

Policymakers designing electricity rates should be wary of unintended consequences – customers' responses to rates are complex and an apparently well-designed rate can deliver unexpected results.

More specifically Navigant's main observations from this analysis are:

Presently, system peak demand is a plateau, not a summit. Rates that target relatively short periods of the day, aiming to reduce system peak will tend to be ineffective and simply shuffle demand to earlier or later hours that are *also* system peak demand hours. This observation may have implications for peak demand reductions attributed to demand response programs, if those programs generate any snapback.[8] Navigant recognizes, however, that the profile of peak demand is evolving and the proliferation of embedded solar generation is likely to change it.

Top ten system peak demand hours can – and often do – occur in Status Quo Off-Peak hours. With the current system load shape, a non-trivial number of the top ten system hours occur in hours with the lowest TOU price. The only way to use electricity prices to reduce consumption in these Off-Peak

[8] "Snapback" refers to an increase in electricity demand immediately following a critical peak pricing or direct load control event that may be attributable to that event.

system peak hours would be either increase the Off-Peak rate or extend the Mid-Peak period later in the day.

The estimated peak demand impacts are based on the net system load shape as it currently is, not necessarily as it may become. Increased penetration of solar PV could considerably alter the system load shape and thus the net system peak demand impacts of the various scenarios. Appendix C (below) illustrates the degree to which peak demand impacts are sensitive to the shape of system demand.

Simply raising the price of electricity in a period will not necessarily reduce consumption in that period. Consider the case of the Flat Scenario – despite the price increasing in the summer Status Quo On-Peak (11am – 5pm) period, the larger price increase in the summer Mid-Peak period (7am to 11am and 5pm to 7pm) resulted in consumption in the Status Quo On-Peak increasing, not decreasing.

A sharper price differential within the current TOU structure could yield meaningful peak demand reductions. Of all the scenarios, the ESQ Scenario yielded the most significant absolute demand reductions. This was for two reasons: undesired cross-price effects were mitigated by maintaining a differential between On-Peak and Mid-Peak prices (unlike in the Flat Scenario) and overall the price of electricity was raised considerably from 7am to 7pm, a period covering most (but not all) of the current system peak hours.

If prices are extremely high in every weekday afternoon of the summer, customer demand shifting could lead to an even higher peak earlier in the day. In the Super-Peak Scenario, the estimated elasticities imply that customers would implement a significant amount of pre-cooling in the earlier hours of the day, which could actually increase the system peak demand.

Calling critical peak periods on consecutive days is likely to mute the desired effect. As modeled, when critical peak periods are called on consecutive days the effectiveness of the rate in reducing peak demand is compromised – customers may become exhausted with responding and may respond less on average to each event. This observed result is driven partly by the manner in which customer price response is modeled – customers are modeled such that they allocate their consumption (as driven by the estimated elasticities) by week. While Navigant believes that this reasonably reflects reality, the hypothesis of reduced critical event effectiveness when events are clustered should be tested.

Given the results of the evaluation discussed above, and Navigant's observations based on these results, Navigant's two key considerations are (i) that increasing the Status Quo price differentials could yield material peak demand reductions and (ii) that there is value in using a pilot program to confirm the accuracy of the modeled behaviour impacts under the CPP and CPD Scenarios.

Even without the use of administrative pricing (i.e., relying on arbitrary ratios such as the 1:3:4 set used for the ESQ Scenario), there are mechanisms in the RPP Manual that would allow more of the Global Adjustment costs to be recovered in the On-Peak and Mid-Peak periods, thus raising the rate in those periods relative to the Status Quo and the Off-Peak price.

A set of CPP and CPD pilot programs could confirm (or dismiss) the modeled findings of this study. In particular:

- the magnitude of customer response to critical peak prices in the event period;
- the magnitude of demand shifting to periods immediately adjacent to the critical peak period (i.e., do the actual own- and cross-price effects resemble those modeled?); and
- the effect on event impacts if a full week of consecutive events are called (i.e., how substantial is event fatigue? does the clustering of peak demand days really affect impacts as modeled?)

Greater certainty of potential program participation obtained though the use of a carefully designed provincial survey could be combined with estimated relationships from a CPP or CPD pilot to provide a robust projection of the provincial benefits of provincial CPP or CPD program.

Table of Contents

List of Figures and Equations

1 Introduction

This report is Part 2 of the Ontario Energy Board's (OEB) study of time-of-use (TOU) rates. Part 1 of this study[9], estimated the impact of the transition from tiered to TOU rates on residential and small commercial electricity consumers in Ontario. One of the major outputs of Part 1 were the estimated own- and cross-price elasticities of the demand for electricity. Part 2 of the study - this report - applies these elasticities to evaluate the impact that changing the current TOU structure could have on four metrics chosen by OEB staff.

This introduction is divided into three sections.

Status Quo TOU Structure and Prices in Ontario. This section provides a brief description of the current TOU structure and prices in Ontario.

- **Study Objective.** This section outlines the objectives of this Part 2 of Navigant's study of TOU rates in Ontario.
- **Structure of this Report**. This section outlines the structure of this report.

Throughout this report, Navigant continues to use the seasonal nomenclature introduced in Part 1 of this study. The definitions of season names are:

- Summer: June through August
- Summer Shoulder: May, September and October
- Winter: December through February
- Winter Shoulder: November, March and April
- RPP summer: May through October – the period corresponding to the current RPP definition of summer.
- RPP winter: November through April – the period corresponding to the current RPP definition of winter.

All times presented in the text and figures of this report are in Eastern Prevailing Time (EPT).

Throughout this report reference is made to "customers". Unless otherwise explicitly noted the reader should understand these to be RPP customers.

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[9] Ontario Energy Board, prepared by Navigant Consulting, *Time of Use Rates in Ontario, Part 1: Impact Analysis*, December 2013

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/Navigant_report_TOU_Rates_in_Ontario_Part_1_201312.pdf

1.1 Status Quo TOU Structure and Prices in Ontario

Under amendments to the Ontario Energy Board Act, 1998 (the Act) contained in the Electricity Restructuring Act, 2004, the Ontario Energy Board (OEB or the "Board") was mandated to develop a Regulated Price Plan (RPP) for electricity prices to be charged to consumers that have been designated by regulation. Designated customers include residential and small general service (<50 kW) customers. The first prices were implemented under the RPP effective on April 1, 2005, as set out in regulation.

The principles that guided the Ontario Energy Board in developing the RPP were established by government. In accordance with legislation, the prices paid for electricity by RPP consumers are based on forecasts of the cost of supplying them and must be set to recover those forecast costs. RPP prices are currently reviewed and adjusted if necessary by the OEB every six months. Any variance between the forecast and actual supply cost is recovered over a 12-month period.

1.1.1 The Status Quo TOU Structure

Consumers with eligible time-of-use (or "smart") meters that can measure and record electricity consumption for hourly (or shorter) intervals will pay under a time-of-use (TOU) price structure. The prices under this plan are based on three TOU periods. These periods are referred to as Off-Peak, Mid-Peak and On-Peak. The timing of the TOU periods is based on Eastern Prevailing Time (EPT) and varies by season. There are two "RPP Seasons" – Winter (November through April) and Summer (May through October). The timing of the TOU periods by season is shown in Figure 1, below. Note that as of May 1, 2011 the afternoon Mid-Peak period (in the summer) and the afternoon On-Peak period (in the winter) were reduced from four to two hours.

Figure 1: RPP TOU Hours in Summer and Winter

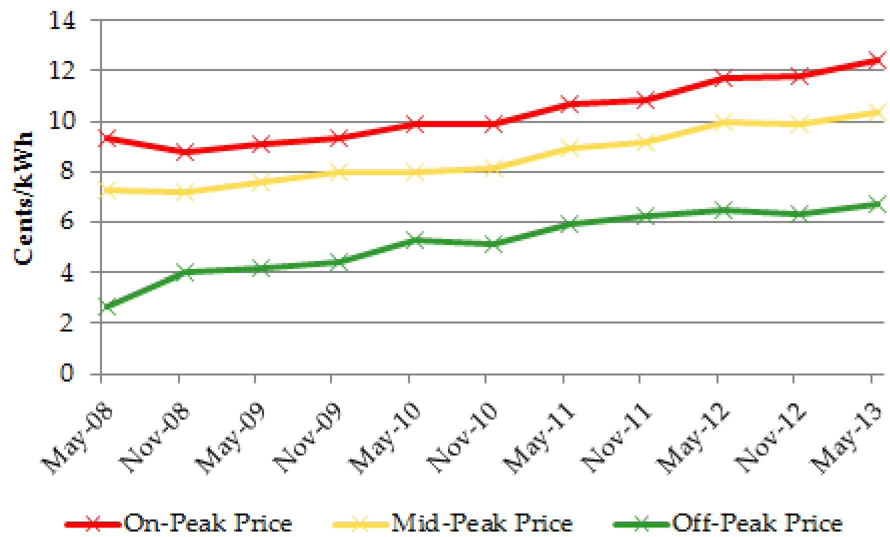
	On-Peak	Mid-Peak	Off-Peak
Prior to May 1, 2011	11am - 5pm Summer Weekdays 7am - 11am and 5pm - 9pm Winter Weekdays	7am - 11am and 5pm - 9pm Summer Weekdays 11am - 5pm Winter Weekdays	9pm - 7am Weekdays, 24 hours on Weekends/Holidays
As of May 1, 2011	11am - 5pm Summer Weekdays 7am - 11am and 5pm - 7pm Winter Weekdays	7am - 11am and 5pm - 7pm Summer Weekdays 11am - 5pm Winter Weekdays	7pm - 7am Weekdays, 24 hours on Weekends/Holidays

Source: OEB website

1.1.2 Status Quo TOU Prices

The RPP TOU prices are reviewed and adjusted every six months. Figure 2 below shows the commodity cost of electricity to TOU customers, by TOU period, at each price setting from May 1, 2008 to May 1, 2013. The May 1, 2013 prices were in effect until October 31, 2013 and were those used to represent status quo prices for the modeling undertaken for this part of the TOU study.

Figure 2: RPP TOU Prices since May 2008



Source: OEB website

A visual representation of the Status Quo prices used in this study, along with the periods to which those prices apply, may be seen in

Figure 3: SQ TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><th>Hour Ending (EPT):</th><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th><th>11</th><th>12</th><th>13</th><th>14</th><th>15</th><th>16</th><th>17</th><th>18</th><th>19</th><th>20</th><th>21</th><th>22</th><th>23</th><th>24</th></tr>
<tr><td>Summer</td><td colspan="7">6.7</td><td colspan="4">10.4</td><td colspan="6">12.4</td><td colspan="2">10.4</td><td colspan="5">6.7</td></tr>
<tr><td>Summer Shoulder</td><td colspan="7">6.7</td><td colspan="4">10.4</td><td colspan="6">12.4</td><td colspan="2">10.4</td><td colspan="5">6.7</td></tr>
<tr><td>Winter</td><td colspan="7">6.7</td><td colspan="4">12.4</td><td colspan="6">10.4</td><td colspan="2">12.4</td><td colspan="5">6.7</td></tr>
<tr><td>Winter Shoulder</td><td colspan="7">6.7</td><td colspan="4">12.4</td><td colspan="6">10.4</td><td colspan="2">12.4</td><td colspan="5">6.7</td></tr>
</table>

Off-Peak Mid-Peak On-Peak

Weekend and holiday prices in each season are the same as weekday prices from 7pm to 7am (hour ending 20 to 7)

Source: OEB and Navigant analysis.

1.2 Study Objectives

Navigant was engaged by the OEB in the spring of 2013 to undertake a two part study of TOU rates

Part 1: Estimate the historical impact of TOU rates on the consumption of a sample of customers drawn from participating local distribution companies (LDCs).

Part 2: Using the results of #1, forecast the impact, all else equal, of five alternative TOU structures (referred to below as "scenarios").

This report addresses Part 2 of the study. Navigant's report that addresses Part 1 of the study is available on the OEB website.

The four metrics used to evaluate each scenario are described below.

Impact on System Peak Demand (Quantitative): the degree to which the given scenario reduces Ontario system peak demand. Navigant has calculated system peak demand as the average IESO Ontario demand during the ten highest system demand hours of the year[10], consistent with the method applied by the Ontario Power Authority (OPA) for calculating that agency's "CF2" peak coincidence factor.[11]

Ease of Implementation (Qualitative): the ease with which the given scenario could be implemented. This metric considers factors such as the technical feasibility of each scenario (i.e., the ability of billing systems to implement it), the degree to which each scenario would likely be accepted by the public and the legal and regulatory implications of each scenario.

Alignment with System Marginal Costs (Quantitative): the degree to which the given scenario's prices reflect the variation in actual short-term system marginal costs, as represented by the wholesale Hourly Ontario Energy Price (HOEP).

Price Stability (Quantitative): the degree to which under- or over-recovery of RPP supply cost (and thus the variance that would need to be collected in the next price-setting) that results from a given scenario potentially increases the volatility of RPP TOU prices.

When considering the overall "performance" of a scenario, these metrics are given equal weight. Navigant recognizes that stakeholders are likely to have different views on the relative importance of each metric.

1.3 Structure of this Report

In addition to this introduction, this report is divided into six chapters, each of which itself is divided into a number of sections. The four main chapters of this report, and their sections, are:

1. **Description of Scenarios, Evaluation Metrics and Informational Outputs.** A description of the TOU structures and prices modeled by Navigant, and of the evaluation metrics and informational outputs applied to all five scenarios.
2. **Scenario Price-Setting Methods.** A description of the method used to determine the commodity prices employed in each scenario.

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[10] Note that this metric does not measure the impact on demand on the ten hours of the year that experienced highest demand in the Status Quo, but rather the difference between the average demand in those hours and the average demand in the "new" top ten hours of the given scenario.

[11] The OPA's "CF2" peak coincidence factor is a parameter estimated by the OPA for conservation measures and programs, and is intended to quantify the degree to which measure or program savings are coincident with system peak. More detail may be found in Appendix A of: Ontario Power Authority, *Prescriptive Measures and Assumptions: Release Version 1*, March 2011

3. **Scenario Behavioural Impact, Quantitative Metric and Informational Output** Methods**.** A description of the methods used to calculate the estimated impact of each scenario of customer behaviour, the value of each quantitative metric and the values of the informational outputs.
4. **Behavioural Impacts and Evaluation Metric Results**. A summary of the estimated behavioural impact of each scenario and the results of Navigant's analysis in each category of evaluation metric.
5. **Informational Outputs.** A summary of informational outputs of the analysis – factors of interest to policy-makers but not metrics weighed to determine the viability or desireablity of any given scenario.
6. **Observations and Considerations.** A summary of the metric values for each scenario, and a conclusion regarding the relative desireability of each one, and recommendations for future policy and research.

2 Description of Scenarios, Evaluation Metrics and Informational Outputs

This section of the report will describe the five scenarios modeled by Navigant, the evaluation metrics used by Navigant to rank each scenario, and the informational outputs provided that give more nuanced understanding of the estimated potential impacts of each scenario.

This chapter is divided into four sections:

- **Test Years and Forecast System Costs.** A description of Navigant's use of test years for the analysis.
- **Evaluation Metrics.** A description and discussion of the four evaluation metrics applied to each of the different TOU scenarios.
- **Informational Outputs.** A description and discussion of the two sets of informational outputs of the analysis.
- **Scenario Descriptions – Structures and Prices**. A description of the pricing structures applied in each scenario, and the prices used for each structure in the analysis.

2.1 Test Years and Forecast System Costs

To reflect the natural variation of electricity demand, Navigant has used two test years as the basis for its analysis, 2011 and 2012. Data from the test years were combined with forecast system costs, RPP and system energy consumption from the May 1, 2013 RPP price setting to set the prices for each scenario and establish status quo levels of demand for the two RPP customer classes and for the Ontario system as a whole.

Thus the *relative* system costs and consumption levels used in the modeling reflect the actual fluctuations and variations observed in 2011 and 2012, but the *absolute level* of system costs and consumption (at the annual or monthly level, as appropriate) reflect those forecast as part of the May 2013 RPP price setting.

All results will be presented for each of the test years and, where appropriate for the average across the two test years.

2.2 Evaluation Metrics

In July 2013, Navigant facilitated a workshop at the OEB. This workshop was used to discuss what scenarios Navigant should model and what metrics should be used to evaluate each scenario. At that workshop, OEB staff decided on three quantitative and one qualitative metric to be used to rank each scenario.

A brief description of the four metrics used to evaluate each scenario is provided below.

Impact on System Peak Demand (Quantitative): the degree to which the given scenario reduces Ontario system peak demand. Navigant has calculated system peak demand as the average IESO Ontario demand during the ten highest system demand hours of the year[12], consistent with the method applied by the Ontario Power Authority (OPA) for calculating that agency's "CF2" peak coincidence factor.[13]

To test the sensitivity of this metric to the underlying system load shape, Navigant has also estimated the impact of each scenario on system peak demand where the system load shape reflects solar PV production forecast by the LTEP by 2020.[14]

Ease of Implementation (Qualitative): the ease with which the given scenario could be implemented. This metric considers factors such as the technical feasibility of each scenario (i.e., the ability of billing systems to implement it), the degree to which each scenario would likely be accepted by the public and the legal and regulatory implications of each scenario.

Alignment with System Marginal Costs (Quantitative): the degree to which the given scenario's prices reflect the variation in actual short-term system marginal costs, as represented by the wholesale Hourly Ontario Energy Price (HOEP).

Price Stability (Quantitative): the degree to which under- or over-recovery of RPP supply cost (and thus the variance that would need to be collected in the next price-setting) that results from a given scenario potentially increases the volatility of RPP TOU prices.

When considering the overall "performance" of a scenario, these metrics are given equal weight. Navigant recognizes that stakeholders are likely to have different views on the relative importance of each metric.

2.3 Informational Outputs

Navigant also provided two "informational outputs". These outputs are distinct from the evaluation metrics in that they are not used to gauge the desireability or performance of the scenarios, but rather to provide policy-makers and analysts a more nuanced understanding of the impacts of each scenario. The two informational outputs are described below.

12 Note that this metric does not measure the impact on demand on the ten hours of the year that experienced highest demand in the Status Quo, but rather the difference between the average demand in those hours and the average demand in the "new" top ten hours of the given scenario.

13 The OPA's "CF2" peak coincidence factor is a parameter estimated by the OPA for conservation measures and programs, and is intended to quantify the degree to which measure or program savings are coincident with system peak. More detail may be found in Appendix A of: Ontario Power Authority, *Prescriptive Measures and Assumptions: Release Version 1*, March 2011

14 Forecast PV production from the Ontario Ministry of Energy's *Long Term Energy Plan* is available at the Ontario Power Authority's website: http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013

Unit Cost Impacts by Customer Type. The "unit cost impact" is the estimated percentage change in how much a given customer type pays, on average, for each kWh of consumption – the sum of commodity (i.e., TOU rate) and non-commodity volumetric costs. The unit cost impacts of three types of customers in each rate class (residential and GS) are estimated:

- Customers with an average load profile.
- "Type 1" customers – customers with relatively high levels of Off-Peak consumption. The unit cost impact for customers whose ratio of Status Quo Off-Peak to Status Quo On-Peak consumption is in the top 10% for all customers the given rate class.
- "Type 2" customers – customers with relatively low levels of Off-Peak consumption. The unit cost impact for customers whose ratio of Status Quo Off-Peak to Status Quo On-Peak consumption is in the bottom 10% for all customers in the given rate class.

Changes in Energy Consumption. The estimated change in annual energy consumption (GWh) relative to the SQ due to the given scenario.

2.4 Scenario Descriptions – Structures and Prices

Navigant analysed five alternative TOU rate structures. Each of these scenarios is analysed in contrast to the current rate structure, referred to as the Status Quo (SQ).

The rates generated for the scenarios were designed on the same cost-recovery basis as the current RPP price-setting approach. Prices are set such that forecast RPP revenues offset the forecast cost to serve RPP consumption, ignoring any customer behaviour changes that may occur in response to those rates.

The sub-sections that follow describe the structure applied for each scenario as well as the prices used for each of the two test years in greater detail.

2.4.1 Status Quo

The Status Quo "scenario" is used as a baseline. The prices used for the entirety of both test years are the RPP TOU prices forecast as part of the May 1, 2013 RPP price-setting and in force from May 1, 2013 through October 31, 2013.

The Status Quo TOU prices, and the periods in which they apply are:

Figure 4: Status Quo TOU Structure and Prices

Status Quo			
	On-Peak	Mid-Peak	Off-Peak
Price ($/kWh)	$0.124	$0.104	$0.067
Applicable period	11am - 5pm Summer Weekdays 7am - 11am and 5pm - 7pm Winter Weekdays	7am - 11am and 5pm - 7pm Summer Weekdays 11am - 5pm Winter Weekdays	7pm - 7am Weekdays, 24 hours on Weekends/Holidays

Source: OEB website

A visual representation of SQ prices and TOU period timing are summarized in Figure 5, below. This figure shows the weekday SQ TOU structure by season (far left column) across the 24 hours of a weekday. The rate for each TOU period is called out within the relevant band of colour. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am.

Figure 5: SQ TOU Structure and Weekday Prices

Scenario TOU Periods - Weekdays Only*																								
Hour Ending (EPT):	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer				6.7					10.4					12.4				10.4				6.7		
Summer Shoulder				6.7					10.4					12.4				10.4				6.7		
Winter				6.7					12.4					10.4				12.4				6.7		
Winter Shoulder				6.7					12.4					10.4				12.4				6.7		

Off-Peak Mid-Peak On-Peak

Weekend and holiday prices in each season are the same as weekday prices from 7pm to 7am (hour ending 20 to 7)

Source: OEB website

2.4.2 Scenario 1: Status Quo with CPP Prices

The CPP Scenario uses the Status Quo TOU structure, but assumes that critical peak pricing (CPP) is made available to customers as a voluntary option. In exchange for paying very high prices between 2pm and 6pm up to fifteen weekdays[15] during the RPP Summer (May through October) with the highest system demand, participating customers pay a discounted price for Off-Peak electricity in the RPP Summer.

The CPP Scenario offers customers the opportunity to reduce the cost of their electricity consumption and contribute to the health of the Ontario electricity system by targeting a small number of hours

[15] For modeling purposes it has been assumed that critical peak events are called on fifteen days in each RPP Summer.

when system demand is highest. The CPP Scenario prices and the periods in which they apply are[16] summarized in Figure 6, below.

Figure 6: CPP Scenario TOU Structure and Prices

Scenario 1: Status Quo With Critical Peak					
	Critical Peak	On-Peak	Mid-Peak	Off-Peak	
				Winter	Summer
Price ($/kWh)	$0.500	$0.124	$0.104	$0.067	$0.057
Applicable period	2pm - 6pm, Top 15 Summer Demand Days	11am - 5pm Summer Weekdays 7am - 11am and 5pm - 7pm Winter Weekdays	7am - 11am and 5pm - 7pm Summer Weekdays 11am - 5pm Winter Weekdays	7pm - 7am Weekdays, 24 hours on Weekends/Holidays	

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The voluntary CPP Scenario weekday prices and TOU period timing are also summarized graphically in Figure 7, below. All coloured periods apply on every weekday of the season indicated whereas cross-hatched periods (i.e., critical peak periods) apply only on those days in which a critical peak event occurs. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am.

Figure 7: CPP Scenario TOU Periods and Prices (Cents /kWh)

Scenario TOU Periods - Weekdays Only*																								
Hour Ending (EPT):	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer				5.7					10.4				12.4			(50)		10.4				5.7		
Summer Shoulder				5.7					10.4						12.4			10.4				5.7		
Winter				6.7					12.4						10.4			12.4				6.7		
Winter Shoulder				6.7					12.4						10.4			12.4				6.7		

Off-Peak Mid-Peak On-Peak

Critical Peak (15 days for Scenario 1, 5 days for Scenario 4)

Weekend and holiday prices in each season are the same as weekday prices from 7pm to 7am (hour ending 20 to 7)

Source: OEB and Navigant analysis

2.4.3 Scenario 2: Flat

The Flat Scenario, unlike the CPP Scenario, is intended as a mandatory TOU structure for all RPP consumers. Whereas the CPP Scenario assumes some customers will volunteer to participate in the CPP rate, the Flat Scenario assumes that all RPP TOU customers will be required to participate. The Flat Scenario eliminates the Mid-Peak period by extending the On-Peak period to cover the majority of daylight hours, from 7am to 7pm (EPT). The price in this period is also higher than the Status Quo On-Peak. This change applies, however, only for six months of the year, the winter (December,

[16] Note that these prices and periods apply only to those voluntarily participating in the CPP rate. Those not participating are subject to the status quo prices and periods shown in Figure **4**.

January, February) and the summer (June, July, August). In the balance of the year (the "Shoulder" months) customers pay a single flat rate that is lower than the Status Quo Mid-Peak price.

The Flat Scenario offers a simplified price structure intended to allow customers the opportunity to reduce the cost of their electricity consumption by incentivizing seasonal conservation behaviours and measures. Although the prices are set administratively to provide the appropriate incentive, they are not so extreme as to be unduly onerous on customers that, for whatever reason, have little capacity to reduce their daytime summer consumption. The Flat Scenario prices and periods in which they apply are summarized in Figure 8.

Figure 8: Flat Scenario TOU Structure and Prices

<table>
<tr><th colspan="5">Scenario 2: Two Period Summer/Winter, One Period Shoulder</th></tr>
<tr><th></th><th>Test Year</th><th>On-Peak</th><th>Shoulder</th><th>Off-Peak</th></tr>
<tr><td rowspan="2">Price ($/kWh)</td><td>2011</td><td>$0.150</td><td>$0.090</td><td>$0.060</td></tr>
<tr><td>2012</td><td>$0.151</td><td>$0.090</td><td>$0.060</td></tr>
<tr><td>Applicable period</td><td>2011 and 2012</td><td>7am - 7pm, Jun. through Aug., Dec. through Feb., Weekdays</td><td>24 hours, Sept. through Nov, March through May.</td><td>7pm - 7am, Jun. through Aug., Dec. through Feb., 24 hours on Weekends/Holidays</td></tr>
</table>

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The mandatory Flat Scenario weekday prices and TOU period timing are also summarized graphically in Figure 9, below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am.

Figure 9: Flat Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><td>Hour Ending (EPT):</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer</td><td colspan="7">6</td><td colspan="12">15</td><td colspan="5">6</td></tr>
<tr><td>Summer Shoulder</td><td colspan="24">9</td></tr>
<tr><td>Winter</td><td colspan="7">6</td><td colspan="12">15</td><td colspan="5">6</td></tr>
<tr><td>Winter Shoulder</td><td colspan="24">9</td></tr>
</table>

Off-Peak On-Peak Shoulder

Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)

Source: OEB and Navigant analysis.

2.4.4 Scenario 3: Summer Super-Peak

The Super-Peak Scenario is also a mandatory TOU structure – it assumes all RPP TOU customers will be required to participate. The Super-Peak Scenario, like the Flat Scenario, eliminates the Mid-Peak period entirely. In all non-summer months (September through May) customers are subject to two weekday TOU periods, an On-Peak (7am to 7pm) and Off-peak (7pm to 7am). Outside of the summer, customers pay a discounted price for On-Peak consumption. During the summer months (June through August) customers are subject to three weekday TOU periods: a Super-Peak (1pm to 7pm), an On-Peak (7am to 1pm), and an Off-Peak (7pm to 7am) period. The On-Peak price remains the same discounted rate as in the non-summer months but the price in the Super-Peak period is more than double the Status Quo On-Peak price.

The Super-Peak Scenario, like the CPP Scenario, offers customers an opportunity to reduce the cost of their electricity consumption and contribute to the health of the Ontario electricity system by targeting the hours of the day in which system demand tends to be highest. Unlike the CPP Scenario, the Super-Peak Scenario offers greater certainty (the Super-Peak period is daily, whereas the Critical Peak periods are irregular) allowing customers to develop daily behaviours that shift their consumption away from the period of the day in which a high percentage of system costs are incurred. The Super-Peak Scenario prices and the periods in which they apply are summarized in Figure 10.

Figure 10: Super-Peak Scenario TOU Structure and Prices

Scenario 3: Summer Super Peak				
	Test Year	Super-Peak	On-Peak	Off-Peak
Price ($/kWh)	2011	$0.324	$0.087	$0.067
	2012	$0.296	$0.092	$0.067
Applicable period	2011 and 2012	1pm - 7pm, Weekdays, Jun. through Aug.	7am - 1pm, Weekdays , Jun. through Aug. 7am - 7pm, Weekdays, Sept. through May	7pm - 7am, Weekdays. 24 Hours, Weekends

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The mandatory Super-Peak Scenario weekday prices and TOU period timing are also summarized graphically in Figure 11, below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am.

Figure 11: Super-Peak Scenario TOU Periods and Prices (Cents /kWh)

<table>
<tr><th colspan="25">Scenario TOU Periods - Weekdays Only*</th></tr>
<tr><td>Hour Ending (EPT):</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer</td><td colspan="7">6.7</td><td colspan="6">8.7</td><td colspan="6">32.4</td><td colspan="5">6.7</td></tr>
<tr><td>Summer Shoulder</td><td colspan="7">6.7</td><td colspan="12">8.7</td><td colspan="5">6.7</td></tr>
<tr><td>Winter</td><td colspan="7">6.7</td><td colspan="12">8.7</td><td colspan="5">6.7</td></tr>
<tr><td>Winter Shoulder</td><td colspan="7">6.7</td><td colspan="12">8.7</td><td colspan="5">6.7</td></tr>
</table>

Off-Peak Mid-Peak On-Peak Super-Peak

***Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)**

Source: OEB and Navigant analysis.

2.4.5 Scenario 4: Status Quo with Critical Peak Day Prices

The CPD Scenario uses the Status Quo TOU structure, but assumes that critical peak day pricing is made available to customers as a voluntary option. The CPD Scenario is very similar to the CPP Scenario, except that instead of the critical peak price applying for only four hours, it applies for twelve hours, from 10am to 10pm, but only on five weekdays in the summer. In exchange for participating, customers pay a discounted rate for On-Peak and Mid-Peak electricity in the RPP summer months

(May through October). In the RPP winter months customers will be subject to the Status Quo TOU prices.

The CPD Scenario offers customers the opportunity to reduce the cost of their electricity consumption and contribute to the health of the Ontario electricity system by targeting a small number of hours when system demand is highest. The CPD Scenario offers customers a more attractive discount than the CPP Scenario by reducing prices during the most expensive parts of the day, rather than the least (i.e. the Off-Peak). The small number of events (five only) also mean that customers' habits would be disrupted on many fewer days than either the CPP Scenario or the Super-Peak Scenario.

Figure 12: CPD Scenario TOU Structure and Prices

Scenario 4: Status Quo with Critical Peak Days					
RPP Summer Only (May 1 - Oct 31)					
	Test Year	Critical Peak Day	On-Peak	Mid-Peak	Off-Peak
Price ($/kWh)	2011	$0.300	$0.111	$0.093	$0.067
	2012	$0.300	$0.112	$0.094	$0.067
Applicable period	2011 and 2012	10am - 10pm, Top 5 Summer Demand Days	11am - 5pm, Weekdays	7am - 11am and 5pm - 7pm Weekdays	7pm - 7am, Weekdays. 24 Hours, Weekends

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The voluntary CPD Scenario weekday prices and TOU period timing are also summarized graphically in Figure 13, below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am.

Figure 13: CPD Scenario TOU Periods and Prices (Cents /kWh)

Scenario TOU Periods - Weekdays Only*																								
Hour Ending (EPT):	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer				6.7					9.3				11.1		(30)				9.3			6.7		
Summer Shoulder				6.7					9.3					11.1					9.3			6.7		
Winter				6.7					12.4					10.4					12.4			6.7		
Winter Shoulder				6.7					12.4					10.4					12.4			6.7		

Off-Peak Mid-Peak On-Peak
Critical Peak (15 days for Scenario 1, 5 days for Scenario 4)

****Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)***

Source: OEB and Navigant analysis.

2.4.6 Scenario 5: Enhanced Status Quo

The ESQ Scenario is, as the name suggests, very similar to the Status Quo. All TOU periods in the ESQ Scenario follow the same schedule as the Status Quo. The only difference are the prices, which are assigned administratively for this Scenario. Prices for each period were set to be cost-recovering (absent behaviour changes as a result of price changes) and to follow an Off-Peak:Mid-Peak:On-Peak set of ratios of 1:3:4.

That is, the prices are chosen such that:

a. There is cost recovery (absent behaviour changes);
b. The Mid-Peak price is three times the Off-Peak price; and,
c. The On-Peak price is four times the Off-Peak price.

The ESQ Scenario offers customers the opportunity to reduce the cost of their electricity consumption by shifting consumption away from the 7am to 7pm period (in which electricity is more costly than in the Status Quo) to the Off-Peak periods, in which electricity is less expensive in the Status Quo. This scenario does not significantly change the incentives facing customers in the Status Quo, merely improves the existing price signal to incent greater customer response than in the Status Quo.

Figure 14: ESQ Scenario TOU Structure and Prices

Scenario 5: Enhanced Status Quo			
	On-Peak	Mid-Peak	Off-Peak
Price ($/kWh)	$0.182	$0.137	$0.046
Applicable period	11am - 5pm Summer Weekdays 7am - 11am and 5pm - 7pm Winter Weekdays	7am - 11am and 5pm - 7pm Summer Weekdays 11am - 5pm Winter Weekdays	7pm - 7am Weekdays, 24 hours on Weekends/Holidays

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

The mandatory ESQ Scenario weekday prices and TOU period timing are also summarized graphically in, below. Weekends and holidays in every season are considered Off-Peak, and the rate is identical to that in effect from 7pm to 7am.

Figure 15: ESQ Scenario TOU Periods and Prices (Cents /kWh)

Scenario TOU Periods - Weekdays Only*																								
Hour Ending (EPT):	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer	4.6							13.7				18.2						13.7		4.6				
Summer Shoulder	4.6							13.7				18.2						13.7		4.6				
Winter	4.6							18.2				13.7						18.2		4.6				
Winter Shoulder	4.6							18.2				13.7						18.2		4.6				

Off-Peak Mid-Peak On-Peak

Weekend prices in each season, for each scenario, will be the same as weekday prices from midnight to 7am (hour ending 7)

Source: OEB and Navigant analysis.

3 Scenario Price-Setting Methods

This chapter describes the methods used by Navigant to generate the prices applied in each scenario. It is divided into the following five sections:

- Status Quo Prices
- Scenario 1: Status Quo with CPP Prices
- Scenario 2: Prices
- Scenario 3: Summer Super-Peak Prices
- Scenario 4: Status Quo with Critical Peak Day Prices
- Scenario 5: Enhanced Status Quo

The approach to setting TOU prices varies by scenario, but for all scenarios prices were set to ensure total cost recovery in each test year, given:

- the underlying commodity price (i.e., HOEP),
- Status Quo consumption profiles,
- the RPP May 2013 forecast absolute level of RPP consumption, and
- the RPP May 2013 forecast of total system costs.

Navigant's price-setting does not iterate the set price based on estimated behaviour changes – prices are set assuming Status Quo levels and timing of consumption. That is, the prices are set such that forecast consumption (absent behaviour changes due to alternative scenarios) will recover forecast system costs. This is consistent with how the RPP TOU prices are set today.

3.1 Status Quo Prices

For the Status Quo, Navigant used the RPP TOU prices set by the OEB in its May 2013 price setting. These were applied for both test year 2011 and 2012.

3.2 Scenario 1: Status Quo with CPP Prices

For the CPP Scenario, for the volunteer CPP participants, Navigant applied the Status Quo TOU prices in RPP Winter months and the Status Quo On-Peak and Mid-Peak prices in the RPP Summer months.

The critical peak price was arbitrarily set at 50 cents per kWh. The discount to be applied to participants' RPP Summer Off-Peak price was determined by the following.

Calculating CPP revenue net of system costs. Navigant calculated the total revenue that would be collected in the CPP hours amongst participating customers, *assuming no behaviour change in response to CPP prices*. Navigant then subtracted the system costs (HOEP and GA) incurred by participating customers in the CPP hours to deliver a net CPP revenue.

Subtracting net CPP revenue from RPP summer Off-Peak system costs. Navigant then subtracted net CPP revenue collected from CPP participants from the summer Off-Peak system costs incurred by CPP participants, again, assuming no change in customer behaviour as a result of the price change. This delivers CPP participants' new summer Off-Peak system costs.

Dividing CPP participants' new summer Off-Peak system costs by CPP participants' summer Off-Peak consumption delivers the discounted Off-Peak price.

3.3 Scenario 2: Flat

For the Flat Scenario, Navigant set prices in each period relative to the Off-Peak price using administrative ratios. Navigant set the ratios as 1 (Off-Peak), 1.5 (Shoulder) and 2.5 (On-Peak).

Prices were calculated in the following manner:

$$P_{t,y} = \frac{r_{t,y} \times Cost_y}{\sum_{t=1}^{3} r_{t,y} \times GWh_{t,y}}$$

Where:

$P_{t,y}$	=	The RPP TOU price in period t (Off-Peak, On-Peak, Shoulder) of test year y.
$r_{t,y}$	=	The administrative ratio used to assign the price in TOU period t. See above for ratios.
$Cost_y$	=	The system cost, in millions of dollars, (HOEP and GA) of total RPP consumption, assuming no behaviour change as a result of the Flat Scenario prices, in test year y.
$GWh_{t,y}$	=	The total RPP consumption, in GWh, in TOU period t and test year y.

3.4 Scenario 3: Summer Super-Peak Prices

For the Super-Peak Scenario, Navigant calculated the Super-Peak price by assigning all peak capacity GA costs to that period. For the Off-Peak, Navigant simply applied the Status Quo Off-Peak price. The On-Peak price was calculated by dividing the residual system costs (total costs less Off-Peak costs and peaking GA costs and Super-Peak HOEP costs) by On-Peak consumption.

Peaking GA costs were calculated by subtracting the average hourly RPP demand from the peak hour of the year and multiplying that number by an estimated cost of capacity - $12,500 per MW-month.

3.5 Scenario 4: Status Quo with Critical Peak Day Prices

For the CPD Scenario, Navigant took an identical approach to The CPP Scenario with the following differences:

The critical peak price was set at 30 cents per kWh, not 50 cents;

The critical peak period was longer (running from 10am to 10pm, rather than from 2pm to 6pm) but occurred on fewer days (five days rather than fifteen); and

The additional net CPD revenue is assigned such that summer On-Peak and Mid-Peak prices are discounted (relative to the Status Quo) by an identical ratio – approximately 10%.

3.6 Scenario 5: Enhanced Status Quo

Prices for the ESQ Scenario were set using the same approach as outlined for the Flat Scenario except that:

- Instead of the three periods being On-Peak, Off-Peak and Shoulder, they were the current (i.e., Status Quo) TOU periods: On-Peak, Mid-Peak and Off-Peak
- Instead of using ratios of 1 (Off-Peak), 1.5 (Shoulder) and 2.5 (On-Peak), Navigant applied the ratios of: 1 (Off-Peak), 3 (Mid-Peak) and 4 (On-Peak).

4 Scenario Behavioural Impact, Quantitative Metric and Informational Output Methods

This chapter describes the methods used by Navigant to model of the five scenarios described above. This chapter is divided into three sections:

- **Estimated Customer Behaviour Impact**. A description of how Navigant estimated the impact of each scenario's prices on customer behaviour (in terms of electricity consumption patterns).
- **Quantitative Metric Calculation.** A description of the methods used to calculate each of the quantitative metrics.
- **Informational Outputs.** A description of the methods used to calculate the two informational outputs.

4.1 Estimated Customer Behaviour Impact

Customer behaviour impacts were derived from the elasticities estimated in Part 1 of this study, and were estimated for each hour of the test year.

This section of this chapter is divided into three sub-sections.

Residential Behaviour Impacts. A description of the approach used to estimate scenario impacts for residential customers.

GS Behaviour Impacts. A description of the approach used to estimate scenario impacts for GS customers.

Participation Rate Assumptions. A description of the assumptions regarding participation rate for Scenarios 1 and 4 and the presentation of evidence supporting those assumptions.

4.1.1 Residential Behaviour Impacts

For each hour and each rate class in each test year, the scenario-specific counterfactual consumption (i.e., what would have been consumed under the given scenario, had the given scenario's structure and prices been in place) was calculated in the following way (a verbal explanation follows):

$$GWh_{i,t,y}^{SC} = \exp\left(\begin{array}{l} \left(\ln\left(mp_{i,t,y}^{SC}\right) - \ln\left(mp_{t,y}^{SQ}\right)\right)\cdot \varepsilon_{t\in k,t\in r,s}^{Magg} + \sum_{r=1}^{R=3}\left(\ln\left(\overline{mp_{i,t\notin r,w,y}^{SC}}\right) - \ln\left(\overline{mp_{t\notin r,w,y}^{SQ}}\right)\right)\cdot \varepsilon_{t\in k,t\notin r,s}^{Magg} \\ \qquad + \ln\left(\theta_i \cdot GWh_{i,t,y}^{SQ}\right) \end{array} \right)$$

Where:

$GWh_{i,t,y}^{SC}$	=	The total residential GWh for scenario i, in hour t of year y, of those customers that are participating in the scenario TOU rate (recall that

Scenarios 1 and 4 are voluntary, whereas scenarios 2 and 3 assume 100% mandatory participation).

$mp_{i,t}^{SC}$ = The average marginal price ($/kWh)[17] to which residential customers are exposed for scenario i, in hour t of year y. The marginal price is defined as the sum of commodity and non-commodity volumetric charges (e.g., distribution charge, etc.) The "average" indicates that the marginal cost was calculated using an average of the non-commodity volumetric costs charged by the LDCs included in the estimation sample (a list of these LDCs may be obtained in Part 1 of this study).

$mp_{i,t,y}^{SQ}$ = The average marginal price ($/kWh) to residential customers are exposed in the Status Quo, in hour t of year y.

$\varepsilon_{t \in k, t \in r, s}^{Magg}$ = The Marshallian[18] *own*-price elasticity[19] of demand taking into account the aggregate elasticity of demand for electricity for season s (i.e., summer, summer shoulder, winter and winter shoulder). The own-price elasticity of demand is defined as the Marshallian elasticity for commodity period k with respect to the price period r, where k = r (i.e., price period and commodity period are the same) and where the hour t falls within commodity period k and price period r.

$\overline{mp_{i,t \notin r, \mathrm{w}, \mathrm{y}}^{SC}}$ = The average marginal price ($/kWh) to which residential customers are exposed in scenario i, price period r, week w and year y, where the current hour t is *not* within the price period r.

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17 The marginal price is the price that a given customer pays for each incremental unit of electricity. The marginal price faced by customers subject to TOU rates is simply the commodity price for the given TOU period, plus volumetric non-commodity costs. Volumetric non-commodity costs are all the per-kWh costs paid by customers that are not part of the commodity charge, e.g. distribution charges, the Debt-Retirement Charge, etc..

18 Marshallian elasticities are so called because of the demand functions from which they are derived. As per Varian (1978): "[The terminology of compensated demand function] comes from viewing the demand function as being constructed by varying prices and income so as to keep the consumer at a fixed level of utility. Thus the income changes are arranged to 'compensate' for the price changes… Hicksian demand functions are not observable since they depend on utility, which is not directly observable. Demand functions expressed as a function of prices and income are observable… we will refer to the latter as the **Marshallian demand function**..." (emphasis in original).

19 The own-price elasticity of demand quantifies the relationship between the price of a good and the quantity of that good demanded. "Normal" goods will have a negative own-price elasticity of demand; as the price increases the quantity demanded falls.

$\overline{mp}^{SQ}_{t \notin r,w,y}$ = The average marginal price ($/kWh) to which residential customers are exposed in the Status Quo, in price period r, week w and year y, where the current hour t is *not* within the price period r.

$\varepsilon^{Magg}_{t \in k, t \notin r, s}$ = The Marshallian *cross*-price elasticity[20] of demand taking into account the aggregate elasticity of demand for electricity for season s (i.e., summer, summer shoulder, winter and winter shoulder). In this case the appropriate cross-price elasticity is that which applies when hour t is within commodity period k, but hour t is *not* within price period r.

θ_i = The participation rate in Scenario i. This is equal to one (or 100%) for Scenarios 2 and 3 and 0.05 (or 5%) for Scenarios 1 and 4. The reasoning behind the assumed participation rate for Scenarios 1 and 4 is explained in below.

$GWh^{SQ}_{i,t,y}$ = The total GWh of residential customers for the Status Quo, in hour t of year y.

The equation above may be described verbally in a relatively simple manner: for each hour of each year, scenario and rate class, the own-price effect is calculated using the specific price changes in the given hour and the relevant own-price elasticity obtained from Part 1 of this study. The cross-price effects are calculated using the *average* price change in each price period over the given week (Monday through Sunday). Cross-price effects require this weekly averaging to allow for inter-daily (as well as intra-daily) shifting – i.e. to allow for customers to shift across weekdays and between weekend days and weekdays.

A table showing residential own- and cross-price elasticities may be found in Appendix A.

4.1.2 GS Behaviour Impacts

In Part 1 of this study, Navigant used a Rotterdam model to estimate the own- and cross-price elasticities of electricity demand for residential and GS customers. Due to shortcomings in the data, Navigant was unable to estimate reasonable elasticities for GS customers in any season except the summer. Additionally, unlike the residential results, there was not a close alignment between the conventional impact estimated results and the elasticity estimated results for GS customers. Given this, Navigant believes it would be imprudent to use the elasticities estimated in Part 1 for evaluating the impacts of the scenarios of Part 2.

[20] A cross-price elasticity quantifies the relationship between the price of one good and the quantity demanded of another good. If a cross-price elasticity between two goods is positive they are substitutes – as the price of one goes up, the quantity demanded of the other also increases. If a cross-price elasticity between two goods is negative they are complements – as the price of one good goes up, the quantity demand of the other good falls.

Despite not having been able to obtain any high-confidence estimates of GS customers' responsiveness to price changes, economic theory and common sense suggest that there must be *some* price-response amongst GS customers, even if it is significantly lower (and thus more difficult to detect) than amongst residential customers.

To model the impact on GS customers' consumption of changes in electricity prices, Navigant has estimated a single own-price elasticity of demand, applicable across all hours in each of the four seasons (summer, summer shoulder, winter and winter_shoulder). This is simply estimated as a quarter (25%) of the average residential own-price elasticities in each of the four commodity periods, weighted by the number of hours per season in each commodity period.[21]

For each hour and each rate class in each test year, the scenario-specific counterfactual consumption (i.e., what would have been consumed under the given scenario, had the given scenario's structure and prices been in place) was calculated in the following way:

$$GWh_{i,t,y}^{SC} = \exp\left(\left(\ln\left(mp_{i,t,y}^{SC}\right) - \ln\left(mp_{t,y}^{SQ}\right)\right)\cdot \varepsilon_s + \ln\left(\theta_i \cdot GWh_{i,t,y}^{SQ}\right)\right)$$

Where:

ε_s	=	The own-price elasticity of GS customers in season s. This is calculated as described immediately above.
θ_i	=	The participation rate in Scenario i. This is equal to one (or 100%) for Scenarios 2 and 3 and 0.025 (or 2.5%) for Scenarios 1 and 4. The reasoning behind the assumed participation rate for Scenarios 1 and 4 is explained below.

All other variables are as described above (but for GS rather than residential customers).

4.1.3 Participation Rate Assumptions

The CPP and CPD Scenarios are, as noted above, assumed to be voluntary – that is, not all RPP customers are compelled to participate in them. To estimate the impact of those scenarios, it is therefore necessary to assume some participation rate.

To determine what a reasonable participation rate would be, Navigant turned to CPP programs in other jurisdictions.

[21] The exception is for the winter shoulder period. For this season, the approach detailed above would deliver a positive own-price elasticity. In this case, therefore, Navigant has simply estimated the own-price elasticity for the winter shoulder season to be the average of the own-price elasticity estimated for the winter and for the summer shoulder seasons.

Despite a very large number of CPP pilot projects implemented throughout North America, there are in fact very few full scale CPP programs.[22] In some cases the program is sufficiently limited in scope and the jurisdiction so small that it is simply an inappropriate comparable (e.g. Gulf Power's Energy Select program). In other cases, the program roll-out is sufficiently recent that no evaluation has yet been published and no confirmed participation numbers are available (e.g., Oklahoma Gas & Electric's SmartHours program).

Navigant believes that PG&E's SmartRate program is the best proxy for a full-blown CPP or CPD deployment in Ontario, although Navigant believes that the difference in the critical peak prices between PG&E's SmartRate program and the proposed CPP and CPD Scenarios would result in higher participation in Ontario than observed in California.

PG&E makes a reasonable proxy for Ontario for two main reasons.

PG&E's customer numbers by rate class are similar to that of Ontario. According to PG&E 2012 Annual Report[23]:

- PG&E has approximately 4.6 million residential customers.[24] In Ontario there are approximately 4.4 million residential customers.[25]
- PG&E has approximately 390,000 small general service customers.[26] In Ontario there are approximately 430,000 general service less than 50 kW customers. [27]

PG&E's SmartAC program (residential A/C direct load control) has a similar level of penetration in its service territory as the OPA's peaksaver program does in Ontario. According to PG&E's PY2012 SmartAC evaluation there were almost 150,000 active SmartAC devices installed in residential

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[22] Due to selection bias it would be inappropriate to extrapolate pilot program participation to the general population, and in any case assigning the denominator for calculating the participation rate is problematic since there is frequently no clear indication of how many customers were offered the chance to participate in the pilot.

[23] Deloitte & Touche, prepared for the Pacific Gas & Electric Company, *2012 Annual Report of Pacific Gas & Electric Company to the Public Utilities Commission of the State of California For the Year Ended December 31 2012*, February 2013

https://www.pge.com/regulation/FERC-Form1/form1-2012.pdf

[24] See page 304.1 of PG&E report cited above.

[25] Ontario Energy Board, *2012 Yearbook of Electricity Distributors*, August 2013

[26] See page 304.1 of PG&E report cited above.

[27] Ontario Energy Board, *2012 Yearbook of Electricity Distributors*, August 2013

households in its service territory.[28] According to the OPA's PY2011 peaksaver evalution there were almost 175,000 active peaksaver devices installed in Ontario.[29]

The most recent numbers published by PG&E[30] indicate that there are approximately 100,000 PG&E residential customers participating in its critical peak rate, roughly 2.15% of the total residential population.

Navigant believes that the proposed CPP and CPD Scenarios would be very likely to achieve higher participation rates than the PG&E program. The principal evidence informing this belief is that the SmartRate critical peak rates are considerably higher than those proposed in either the CPP or the CPD Scenario.

Recall that the CPP Scenario proposes a critical peak rate of 50 cents per kWh for four hours on event days (with a discount for Off-Peak consumption), and the CPD Scenario proposes a critical peak rate of 30 cents per kWh for twelve hours on event days (with a discount for Mid-Peak and On-Peak consumption on non-event days). In contrast, PG&E's SmartRate charges *an incremental* 60 cents per kWh during events. Considering that PG&E customers on the standard inclining block rate schedule[31] already pay between 13 cents and 35 cents per kWh (PG&E calculates that the "average total rate" is approximately 20 cents per kWh)[32], this means that the effective critical peak rate is on average 80 cents per kWh. This is considerably higher than the 50 cents per kWh price proposed by The CPP Scenario and nearly three times the critical peak price (30 cents per kWh) proposed by the CPD Scenario.

Given the vastly more expensive critical peak price in PG&E's service territory, Navigant thinks it reasonable to assume that a residential participation rate of 5% in either the proposed CPP Scenario or CPD Scenario is achievable, given reasonable efforts by the various Ontario energy agencies to promote the rate.

Although PG&E does have a CPP rate for non-residential customers ("Peak Day Pricing"), this is one in which it is automatically enrolling all of its small and medium business customers, with the

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28 Freeman, Sullivan & Co, Prepared for Pacific Gas & Electric, *2012 Load Impact Evaluation for the Pacific Gas and Electric Company's SmartAC Program*, April 2013

http://fscgroup.com/reports/2012-smartac-evaluation.pdf

29 Freeman, Sullivan & Co, Prepared for the Ontario Power Authority, *2011 Residential and Small Commercial peaksaver®*, September 2012

http://www.powerauthority.on.ca/sites/default/files/page/2011peaksaverLoadImpactEvaluation.pdf

30 PG&E Currents, *PG&E's SmartRate Program Tops 100,000 Participants*, May 2013

http://www.pgecurrents.com/2013/05/28/pge%E2%80%99s-smartrate-program-tops-100000-participants/

31 Approximately 70% of PG&E's residential customers are subject to this rate schedule. See 2012 Annual report cited above and:

http://www.pge.com/tariffs/electric.shtml#RESELEC_TOU

32 Pacific Gas & Electric, *Electric Rates*, accessed 19 Nov 2013

http://www.pge.com/tariffs/electric.shtml#RESELEC_TOU transition to be complete by 2014.[33] That is, it is a mandatory enrollment program, so a comparison with the voluntary programs proposed by the CPP and CPD Scenarios would be inappropriate. Given the fact that GS customers appear less flexible in their short-term demand response capabilities, Navigant has assumed that the willingness of GS customers to participate would be approximately half of that of residential customers. That is, Navigant has assumed a participation rate of 2.5%.

4.2 Quantitative Metric Calculation

In consultation with OEB staff Navigant established four metrics to evaluate the five different scenarios. One of these metrics – the ease of implementation - is qualitative. The remaining three are quantitative – they are calculated based on the model outputs and other Ontario electricity system data. This section describes the methods used to calculate the values for these three quantitative metrics and is divided into three parts.

Impact on System Peak Demand. A description of how Navigant calculated each scenario's impact on system peak demand.

Alignment with System Marginal Costs. A description of how Navigant calculated the degree to which each scenario's prices reflects the variation in actual system marginal costs.

Price Stability. A description of the degree to which under- or over-collection as a result of each scenario would increase the volatility of RPP TOU prices.

4.2.1 Impact on System Peak Demand

For the purposes of this study, system peak demand is calculated as the average hourly IESO system demand in the top ten hours of the year. As noted above, Status Quo system peak demand is based on the hourly Ontario demand profiles (obtainable on the IESO website) scaled for total annual system consumption forecast as part of the May 2013 RPP price-setting for the May 2013 – April 2014 period. The system peak demand of each scenario is calculated as the average of the demand in the top ten hours of the year *taking into account behaviour changes* that reflect the new prices (and where applicable participation) of each scenario.

The impact of each scenario on system peak demand is simply calculated as the average of the difference between the top ten hours in the Status Quo and the given scenario. Note that the method above means that the top ten hours in the Status Quo will not necessarily correspond to the same hours for a given scenario. An example may be useful as an illustration.

Suppose the tenth highest system demand hour in the Status Quo occurs between 3pm and 4pm on July 15th and corresponds to 25 GW of demand and that the 11th highest system demand hour in the Status Quo occurs between 4pm and 5pm on the same day and corresponds to 24 GW of demand.

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[33] Pacific Gas & Electric, *Peak Day Pricing: What You Need to Know*, accessed 19 Nov 2013 http://www.pge.com/en/mybusiness/rates/tvp/peakdaypricing.page?WT.mc_id=Vanity_pdp

If a given scenario reduces demand between 3pm and 4pm on July 15th by 2 GW but does not affect the demand between 4pm and 5pm, then the system demand impact of that scenario on the 10th highest demand hour will be 1 GW and *not* 2 GW.

This is because the hour that was previously the 11th highest demand hour has now become the 10th highest demand hour and the comparison is now between the demand from 3pm to 4pm on July 15th (Status Quo 10th highest demand hour) and the demand from 4pm to 5pm on July 15th (given scenario 10th highest demand hour), and *not* between the demand from 3pm to 4pm in the Status Quo and the demand in the same time period in the given scenario.

4.2.2 Alignment with System Marginal Costs

The output of this metric is a ranking of each scenario, based on the Euclidean distance between the normalized average weekday prices in each scenario and the normalized average weekday marginal system costs (represented by the HOEP) in each hour.

Navigant has used the forecast HOEP[34] (the same as used to set each scenario's prices) in each hour to represent system marginal cost. The scenario-specific prices used are those that apply to scenario participants. That is, for the CPP and CPD Scenarios, this metric compares the prices to which participants are subject with system costs, and not a weighted average customer price (i.e. an average of Status Quo and critical peak prices).

For each scenario, test year and season, Navigant has calculated the difference between the normalized scenario price and the normalized system cost in each hour of an average weekday. The scenario where the sum of the absolute value of these differences is lowest is deemed to be the most aligned with system costs.

4.2.3 Price Stability

The output of this metric is the variance relative to the Status Quo, in millions of dollars, between total forecast system costs and the revenues in each scenario.

This metric is simply calculated as the sum of the RPP May 2013 forecast global adjustment and the forecast HOEP times the scenario-specific consumption in each year, less the RPP revenue collected under each scenario. A higher variance (in absolute terms) means less price stability since that variance will necessarily have to be collected in the following year.

4.3 Informational Outputs

In consultation with OEB staff Navigant determined that in addition to the four metrics that would be output for each scenario, Navigant would also estimate two informational outputs. These are

34 Hourly forecast HOEP was developed by using actual hourly HOEP in each test year and calibrating it to the forecast monthly peak (defined in that forecast as 7am – 11pm EST non-holiday weekdays) and off-peak HOEP that was estimated as part of the May 2013 RPP price-setting.

intended to add nuance to the understanding of each scenario's impact but are not intended to be used to rank the scenarios.

Unit Cost Impacts by Customer Type**.** A description of how Navigant estimated the average unit cost ($/kWh) impact for residential and GS customers in each scenario, relative to the Status Quo.

Changes in Energy Consumption. A description of how Navigant estimated the aggregate energy savings for each scenario, and test year.

4.3.1 Unit Cost Impacts by Customer Type

This informational output is the impact, as an average percentage change, on the average unit cost o for three types of customers in both rate classes. The "unit cost impact" is the estimated percentage change in how much a given customer type pays for each kWh of consumption – the sum of commodity (i.e., TOU rate) and non-commodity volumetric costs.

Navigant estimated the unit cost impact for customers with the average load profile ("average" customers), customers with relatively high levels of Status Quo Off-Peak consumption ("Type 1" customers) and customers with relatively low levels of Status Quo Off-Peak consumption ("Type 2" customers).

Type 1 customers are more precisely defined as customers whose annual ratio of (Status Quo) Off-Peak consumption to total consumption is in the top decile (i.e., the top 10%), and Type 2 customers are defined as customers whose annual ratio of Off-Peak consumption to total consumption is in the bottom decile (i.e., the bottom 10%).

To estimate unit cost impacts, Navigant first generated an average per customer load profile for the three types of customers. The average customer profile for each rate class was the same as that used to generate the aggregate rate class load shape – simply the average hourly consumption of customers in 2011 and 2012 (the two test years), when those customers were subject to TOU rates.

Type 1 and Type 2 load profiles were created by first isolating Type 1 and Type 2 customers in test years 2011 and 2012, as described above, and then taking the average level of consumption in each hour.

Average unit cost impacts by customer type were estimated by calculating the variable cost to each customer type in each hour of the given test year, summing across the year, and dividing by the consumption in the given test year to deliver a $/kWh unit cost impact. Note that the variable cost to each customer includes both the commodity cost (i.e., the Status Quo or scenario TOU price) as well as the volumetric non-commodity costs (i.e., distribution charges, etc.)

5 Behavioural Impacts and Evaluation Metric Results

This chapter provides the results of the analysis and is divided into six sections.

- **Behavioural Impacts.** A description of the behavioural impacts on the average customer, by rate class, in each scenario.
- **System Peak Demand Impacts**. A description of the system peak demand impacts estimated for each scenario.
- **Ease of Implementation.** A discussion of the relative ease of implementation for each scenario.
- **Alignment with System Costs.** An analysis of how closely the prices in each scenario reflect the marginal system costs.
- **Price Stability.** An analysis of the degree to which each scenario would affect RPP price stability from year to year.
- **Summary of Metrics**. A summary of the metric outputs and rankings and a discussion of the implications.

5.1 Behavioural Impacts

This section provides graphic illustration of the impact of each scenario's prices on the consumption of an average customer from each rate class in each scenario. These impacts are calculated as outlined in 4.1.1 and 4.1.2, except instead of being applied to total participating rate-class consumption, these are applied to the average individual levels of consumption.

Note that in all cases, residential behaviour impacts are derived entirely from the estimated elasticities, and GS behaviour impacts have been derived from the own-price elasticity estimated for that rate class and described above. No other "post-processing" or thresholds have been applied to the model outputs.

In some of the scenarios outlined below the estimated elasticities are being applied considerably outside of the sample in which they were estimated – at no point in the historical period within which the elasticities were estimated, for example, was the price of electricity 50 cents per kWh (as it can be in the CPP Scenario). This means that actual customer behaviour when confronted with the modeled prices may not conform with the behaviour impacts modeled. This is an unavoidable risk when modeling behaviour so far out of the sample from which the behavioural relationships (i.e., the elasticities) were estimated and the reason why Navigant has indicated in chapter 7 that one or more pilot programs would be very useful for testing how well these estimates perform out of sample.

To demonstrate the sensitivity of the behavioural impacts to the estimated elasticities, in addition to the estimated impact of each scenario on average customer consumption behaviour, Navigant has estimated and plotted the estimated impact of each scenario on average customer consumption behaviour when:

a. Elasticities are 50% of those estimated
b. Elasticities are 150% of those estimated

5.1.1 Scenario 1: Status Quo with CPP Prices

This sub-section provides plots describing the estimated impact of The CPP Scenario prices on customers participating in the CPP Scenario's CPP program and responding as indicated by the estimated elasticities.

Note that these responses are for an average participant in the CPP rate – impacts at the system level will not be nearly so extreme since only 5% of residential customers and 2.5% of GS customers are assumed to participate in the program.

Figure 16, below compares the Status Quo residential average consumption per person per hour (black line) and the CPP Scenario residential average consumption per person per hour for a participating customer (blue line) on days in which a CPP event occurs in test year 2011. Estimated average consumption per person per hour when elasticities are 50% of those estimated is represented by the narrow dotted line, and estimated average consumption per person per hour when elasticities are 150% of those estimated is represented by the narrow dash-dotted line.

As expected, the average participating customer's consumption falls considerably during the critical peak period (2pm – 6pm) and increases in the adjacent periods as the customer shifts consumption away from the most expensive part of the day. Note that in addition to the large (expected) level shifts in the CPP Scenario consumption that occur at the border hours of the critical peak period[35] there is an also abrupt level shift within the critical peak period in the hour from 5pm to 6pm (hour ending 18). This is due to the transition from one commodity period[36] ("Middle" from 11am to 5pm) to another ("Shoulder PM 1", from 5pm to 7pm).

There are two reasons for the abrupt shift.

Different elasticities apply in the 5pm to 7pm period than in the 11am to 5pm period.

Within the critical peak period, the price differential between the scenario prices and the Status Quo prices is larger in the 5pm and 6pm period (formerly part of the Mid-Peak period) than it is between 2pm to 5pm period (formerly part of the On-Peak period).

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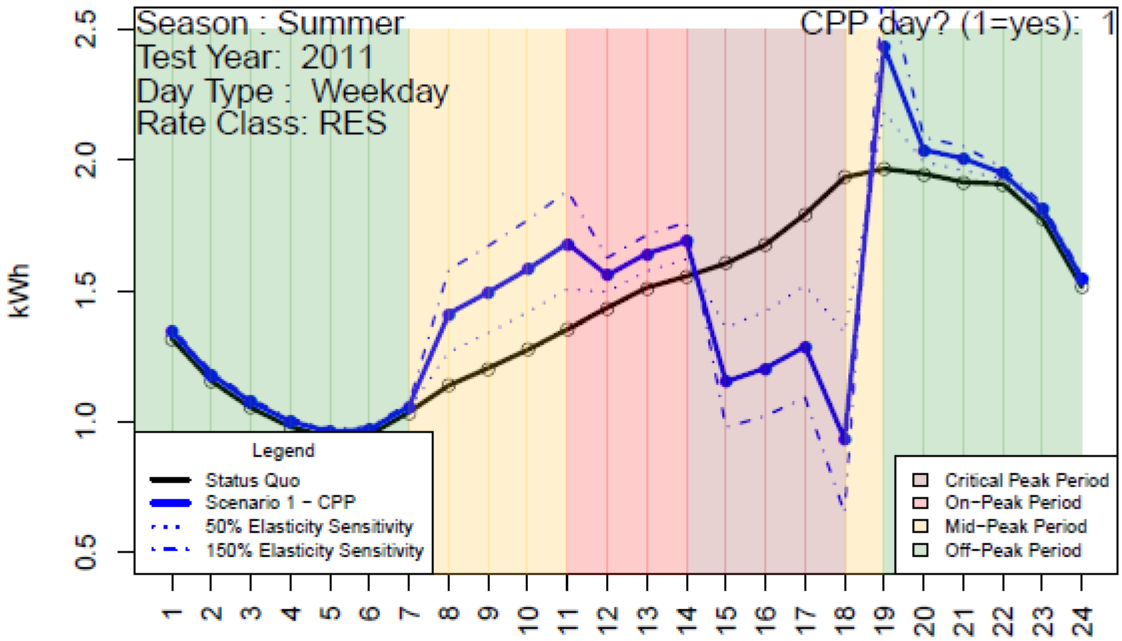
[35] i.e., from 2pm to 3pm (hour ending 15) and from 6pm to 7pm (hour ending 19).

[36] For complete definitions of commodity periods please see Part 1 of this study.

Figure 16: CPP Scenario Residential Profile on CPP Days – Test Year 2011



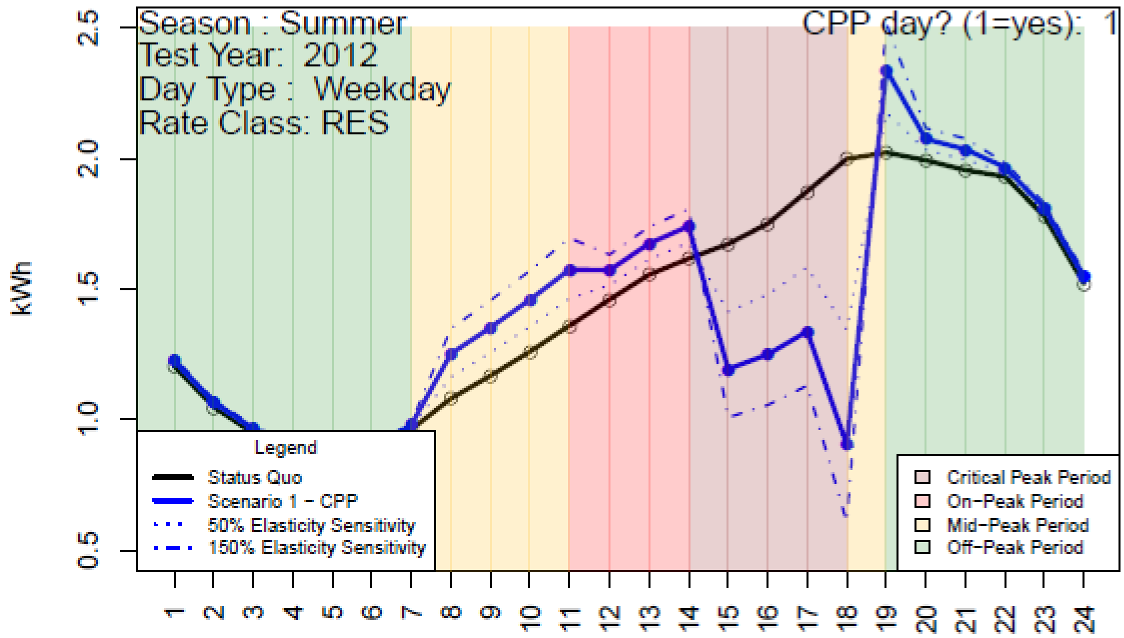
Source: OEB-provided hourly consumption data and Navigant analysis

As noted above, the prices applied in the CPP periods of the CPP Scenario are considerably outside those observed in the estimation sample, and so caution must be used in interpreting the results above. The most intuitive interpretation (subject to the caveats above) is that customer response is dominated by air-conditioning response; customers pre-cool their homes prior to the critical peak period, turn up their thermostats during the event and then turn them back down again immediately following the event.

Figure 17 shows the impact of CPP prices on program participant behaviour for test year 2012. Note that for test year 2012 the reduction in the peak period is very similar as for test year 2011 (Figure 16), the "pre-cooling" impact is smaller. This is a result of the underlying system demand, which drives the days on which critical peak events are called.

In test year 2011 critical peak days were more tightly clustered than for test year 2012. In at least one week in test year 2011 all five weekdays had a critical peak event. In test year 2012 by contrast the underlying system peak demand results in a maximum of only three consecutive days of critical peak events. The impact of having critical peak events "clustered" in this manner is discussed in more depth in 5.1.4, below, for the CPD Scenario where the impacts of such "clustering" are more pronounced.

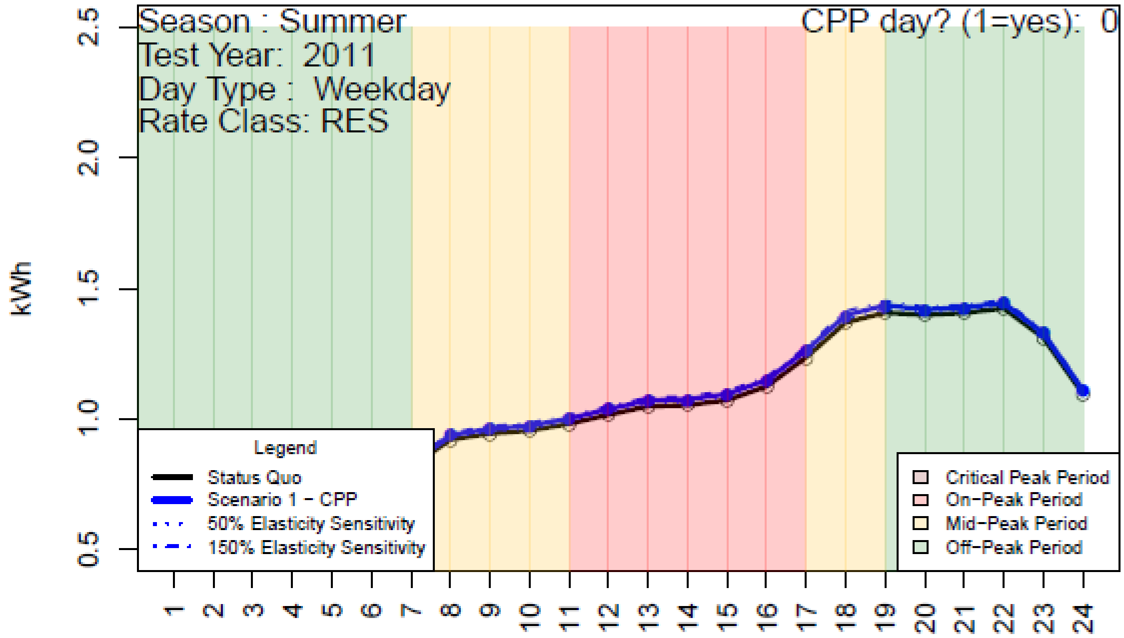
Figure 17: CPP Scenario Residential Profile on CPP Days – Test Year 2012



Source: OEB-provided hourly consumption data and Navigant analysis

For the CPP Scenario, the principal residential behaviour impact occurs on CPP days, since it is on those days that the largest price differentials may be found. Very mild effects may also be observed on non-CPP summer weekdays. As may be seen in Figure 18, consumption increases very slightly on these days in the Mid-Peak and On-Peak periods. This is due to weekly cross-price effects – the more expensive critical peak price results in some moderate inter-daily/intra-weekly shifting. Of course a very mild increase in Off-Peak consumption may be observed on all days of the Summer. The nearly trivial Off-Peak increase on all summer days is due to the fact that the discount offered participating customers is relatively small (approximately one cent per kWh) and that, as indicated by the estimated elasticities, demand for electricity in this period tends not to be very responsive to changes in price.

Figure 18: CPP Scenario Residential Profile on Non-CPP Summer Weekdays

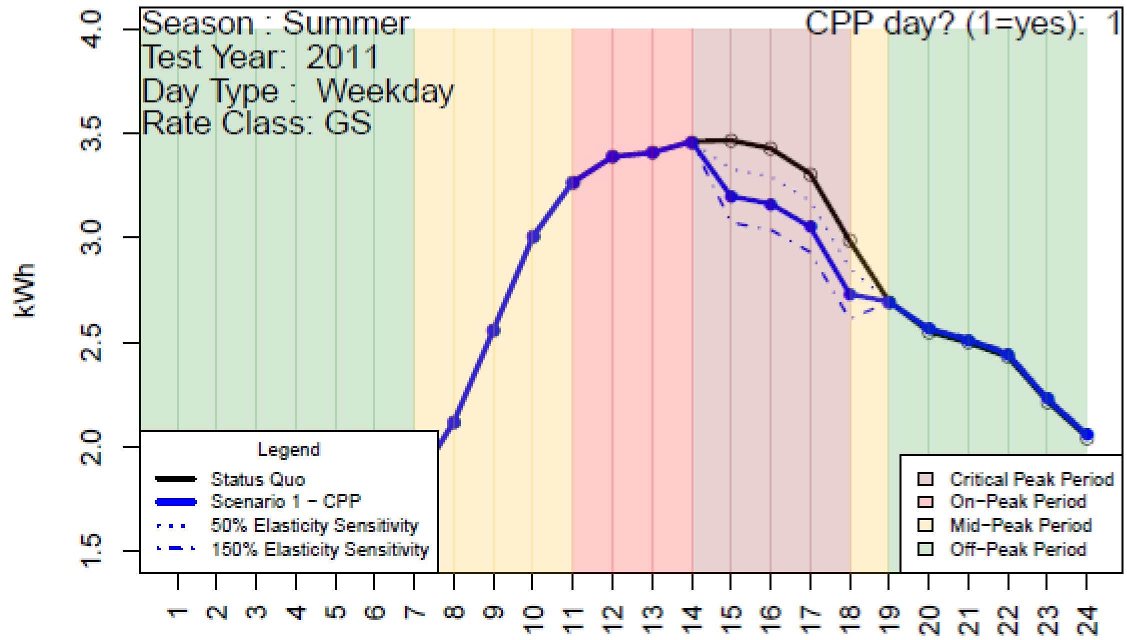


Source: OEB-provided hourly consumption data and Navigant analysis

There is no impact in the winter months – in those months prices are identical to those of the Status Quo.

The estimated impact of the CPP Scenario on an average GS customer on critical peak event days is shown in Figure 19, below. No impact is estimated outside of the critical peak periods (where prices are higher than the Status Quo) or the Off-Peak periods (where prices are slightly lower than the Status Quo). This is by construction – recall from above that for GS customers Navigant is applying only an estimated own-price elasticity.

Figure 19: CPP Scenario GS Profile on CPP Days



Source: OEB-provided hourly consumption data and Navigant analysis

5.1.2 Scenario 2: Flat Impacts

This sub-section provides plots describing the estimated impact of the Flat Scenario prices on electricity consumption. Recall that in the Flat Scenario, in December, January, February, June, July and August, customers pay a single On-Peak price from 7am to 7pm on non-holiday weekdays (that is higher than the SQ On-Peak price) and an Off-Peak price that is lower than the SQ Off-Peak price the remainder of the time. In all other months, customers pay a single Shoulder price that is less than the SQ Mid-Peak price, but higher than the SQ Off-Peak price.

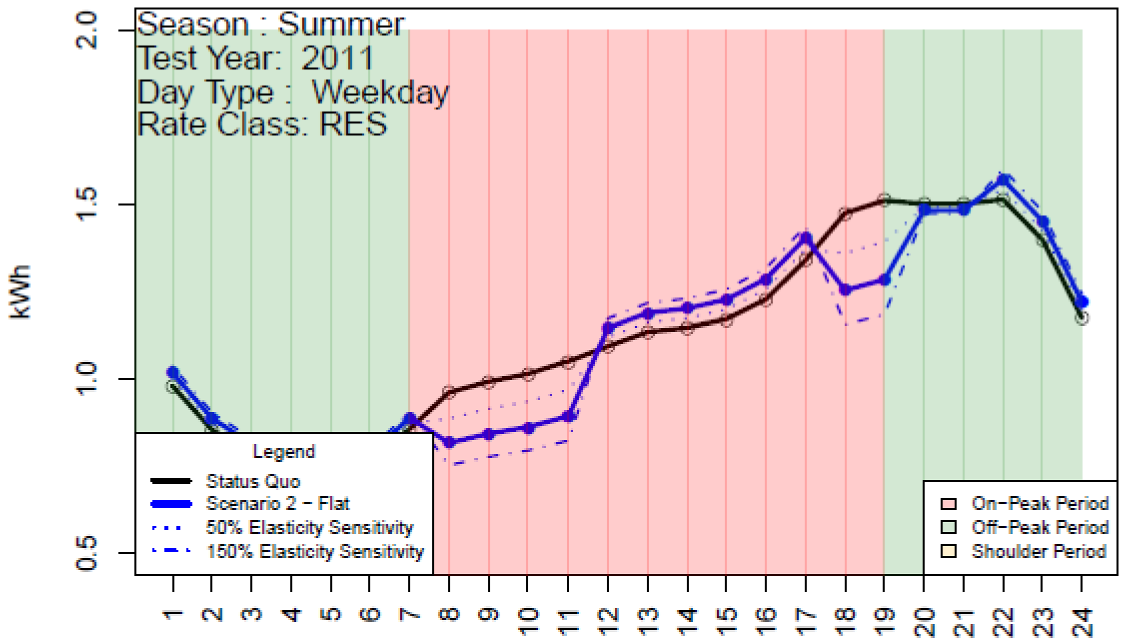
Figure 20 compares the Status Quo residential average summer (June, July, August) consumption with the Flat Scenario residential average summer consumption. Recall that in this scenario the On-Peak price is higher than in the Status Quo, in exchange for a much lower price (in all hours of the day) in the Shoulder months (September through November and March through May). As above, the black line represents Status Quo average consumption, the blue line represents the scenario average consumption (i.e., after behaviour change) and the narrow dotted and dash-dotted lines represent the scenario average consumption if elasticities are 50% of those estimated or 150% of those estimated, respectively.

With this in mind, the plotted results initially appear counter-intuitive – the price in the Status Quo On-Peak period have gone up, but so too has consumption. This unexpected impact is a result of cross-price effects overwhelming own-price effects.

The price in the Status Quo On-Peak period (11am to 5pm) has increased by about 20% (from 12.4 cents per kWh to 15 cents per kWh) leading to a reduction in consumption in that period due to the own-price effect. This effect has then been overwhelmed and reversed due to the cross-price effect of the change in price in the Status Quo Mid-Peak periods (7am to 11am and 5pm to 7pm). The price in those periods has increased by nearly 45% (from 10.4 cents per kWh to 15 cents per kWh).

Put more simply, the average residential customer has shifted more of his consumption away from the Status Quo Mid-Peak period (7am to 11am and 5pm to 7pm) and into the Status Quo On-Peak (11am to 5pm) period than he has shifted away from the Status Quo On-Peak period (11am to 5pm) *resulting in a net increase in consumption in the Status Quo On-Peak period.*

Figure 20: Flat Scenario Residential Summer Weekday Profile

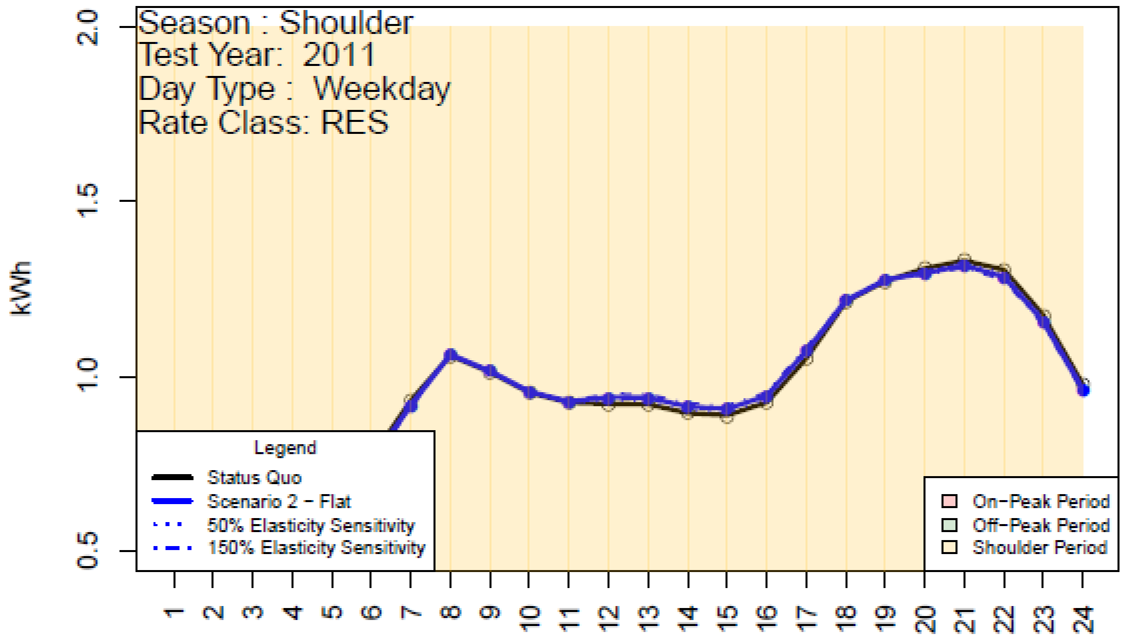


Source:, OEB-provided hourly consumption data and Navigant analysis

The abrupt level shifts observed in Figure 20 are, of course, an artefact of the modelling method (i.e., the use of discrete commodity periods to define elasticities) – in reality the blue line would likely be much smoother. It does, however, illustrate the importance of considering the entire pricing ecosystem as a whole, rather than individual periods in isolation, and the possible unintended consequences of changing prices. Simply increasing the price of consumption in a period *does not guarantee that consumption in that period will fall*.

Figure 21 shows the residential behaviour impact in the shoulder months (March through May and September through November). Behavioural impacts are as expected – periods in which the price of electricity fell also see increases in consumption, whereas periods in which the price of electricity rose see reductions in consumption. Recall that the shoulder period price is a flat 9 cents per kWh during all hours of the day, 7 days a week. Status Quo On-Peak (11am to 5pm in summer months, 7am to 11am and 5pm to 7pm in winter months) and Mid-Peak (7am to 11am and 5pm to 7pm in summer months, 11am to 5pm in winter months) periods have fallen in price, but the Status Quo Off-Peak period (7pm to 7am) has seen an increase in price of nearly a 50% (from 6.7 cents to 9 cents). The relatively mild impact on Status Quo Off-Peak (7am to 7pm) consumption is due to the relatively low level of price responsiveness in this period, as estimated in Part 1 of this study.

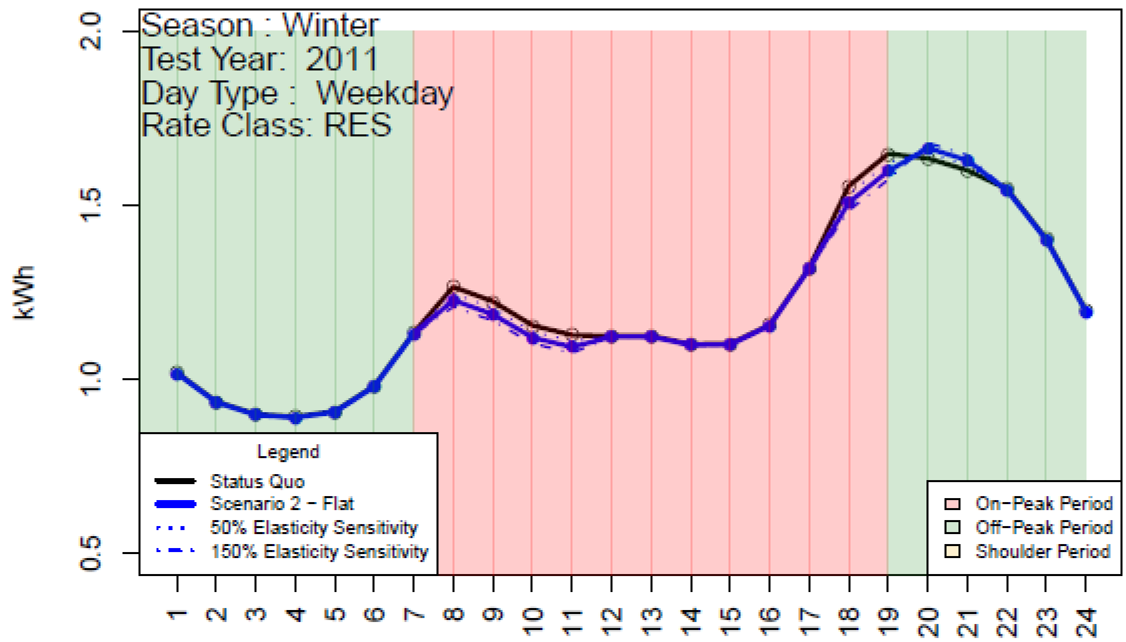
Figure 21: Flat Scenario Residential Shoulder Profile



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 22 shows the average residential behaviour impact in the winter months (December, January and February). The winter impacts are considerably milder than those estimated for the summer months due to the lower level of price sensitivity in this season, as estimated in Part 1 of this study.

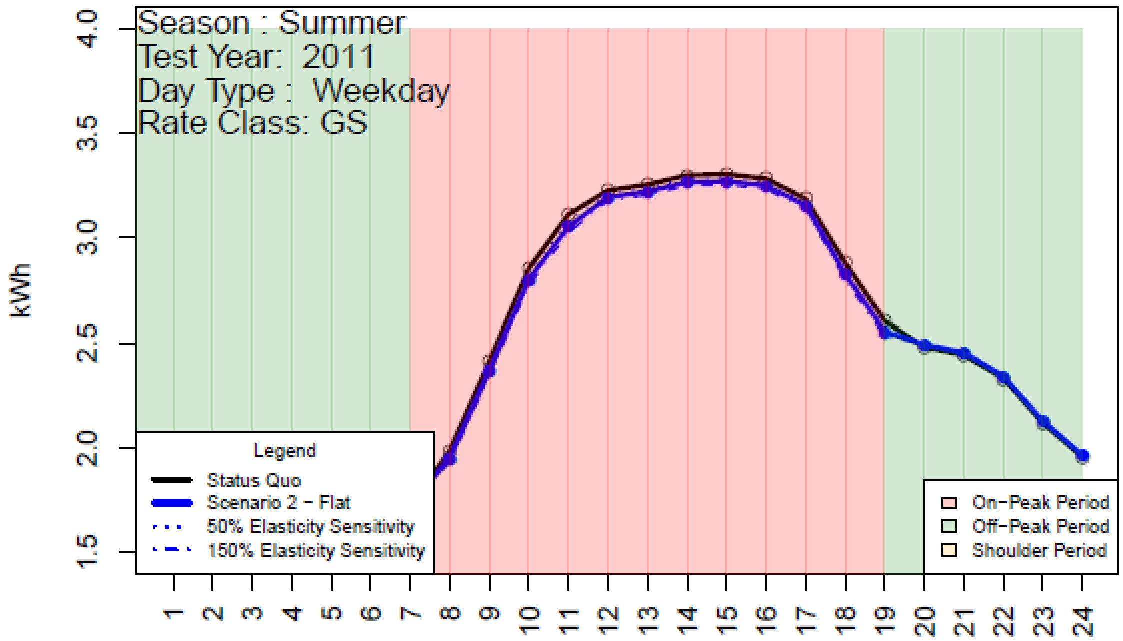
Figure 22: Flat Scenario Residential Winter Profile



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 23 shows the average GS behaviour impact of Flat Scenario in the summer months. The impacts are as expected: there is a mild reduction in consumption during the Status Quo On-Peak (11am to 5pm) and Mid-Peak (7am to 11am and 5pm to 7pm) periods reflecting the increase in the price of electricity in those periods, and a very small, nearly trivial, increase in Off-Peak consumption (7pm to 7am) due to the very small price reduction in that period from the Status Quo. GS impacts in the other seasons are exactly as expected and slightly milder due to smaller own-price elasticities.

Figure 23: Flat Scenario GS Summer Profile



Source: OEB-provided hourly consumption data and Navigant analysis

5.1.3 Scenario 3: Summer Super-Peak

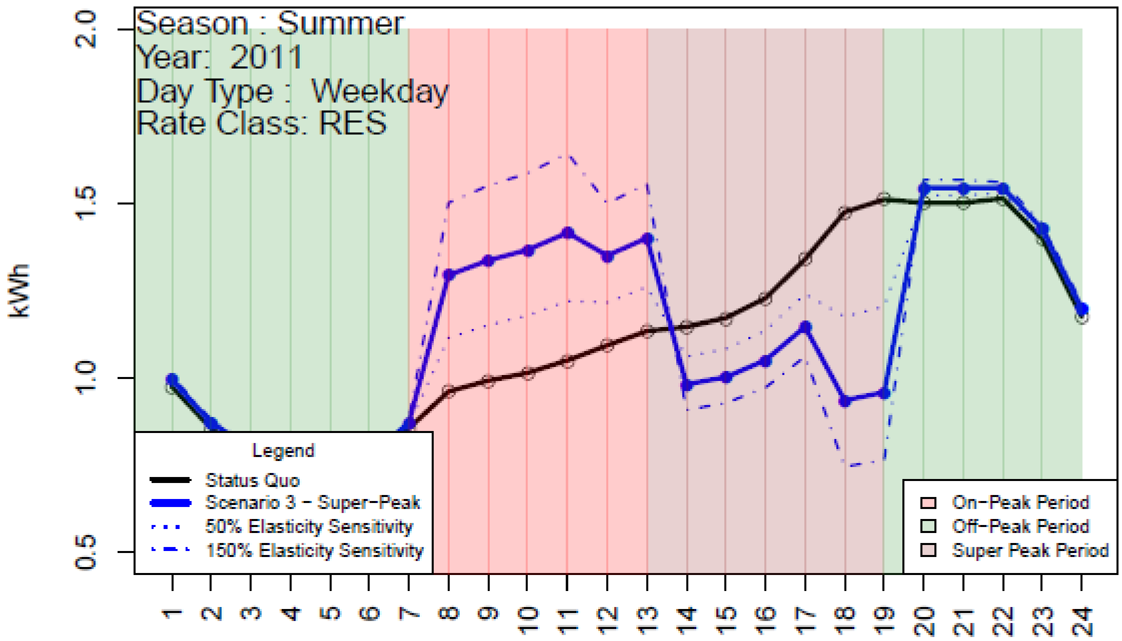
This sub-section provides plots describing the estimated impact of the Super-Peak Scenario prices on electricity consumption. Recall that in the Super-Peak Scenario in June through August, customers pay a very high Super-Peak price between 1pm and 7pm in exchange for a much lower On-Peak price from 7am to 1pm in June through August and from 7am to 7pm the remainder of the year.

Figure 24 shows the residential behavioural impact of the summer Super-Peak prices imposed in the Super-Peak Scenario. Recall that in the Super-Peak Scenario, the price for electricity in the Super-Peak period is approximately 30 cents per kWh and the price in the On-Peak period is approximately 9 cents per kWh. Given these price changes, impacts are as expected, consumption increases in the RPP Summer morning Mid-Peak period (7am to 11am) until the start of the Super-Peak period, when consumption declines. As above, the black line represents Status Quo average consumption, the blue line represents the scenario average consumption (i.e., after behaviour change) and the narrow dotted and dash-dotted lines represent the scenario average consumption if elasticities are 50% of those estimated or 150% of those estimated, respectively.

The step change in consumption that occurs in Super-Peak Scenario behaviour at 5pm is due to the fact that the relative price increase in the Status Quo Mid-Peak period (5pm – 7pm) is higher than the relative price change in the Status Quo On-Peak period (11am to 5pm). The dramatic increase in consumption in the the Super-Peak Scenario On-Peak period (7am to 1pm) is due to the combined own-price effect of the reduction in price in this period from 10.4 (Status Quo Mid-Peak) and 12.4 (Status Quo On-Peak) cents per kWh to approximately 9 cents per kWh, and the cross-price effect of the increase in price during the Super-Peak period.

As in the CPP Scenario, the shifting of consumption to the period immediately preceding the high-price period suggests that the response to this Scenario takes the form predominantly of pre-cooling. However, the price changes in the Super-Peak Scenario are outside the range of those used to estimate the elasticities in Part 1, and at no point in the estimation sample were such dramatically divergent price changes observed.

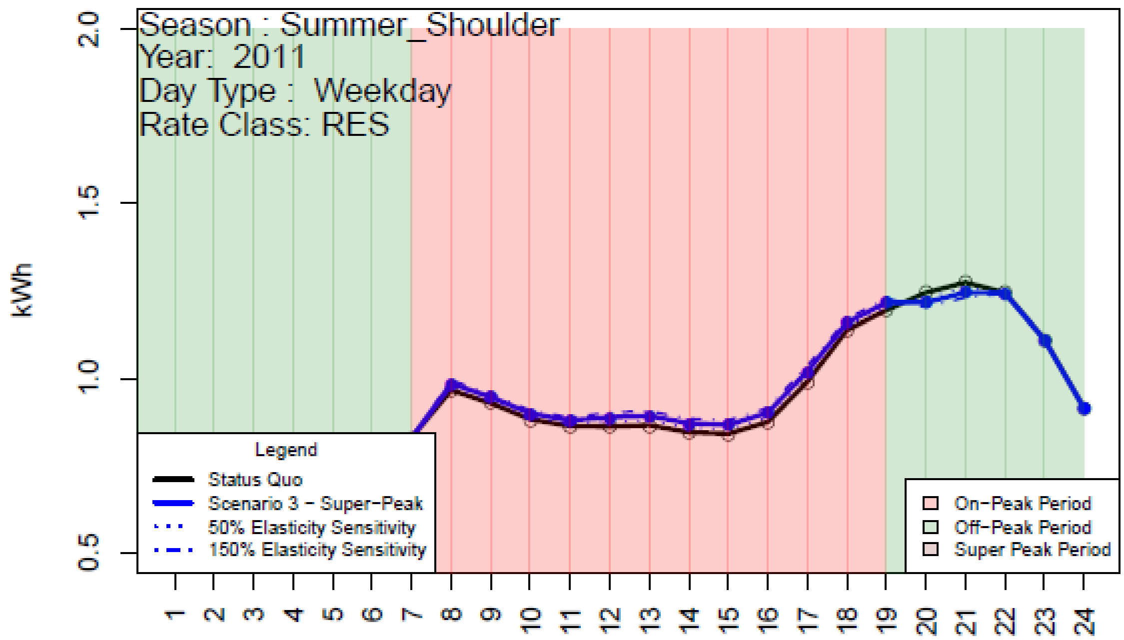
Figure 24: Super-Peak Scenario Residential Summer Profile



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 25 shows the residential behaviour impact of the Super-Peak Scenario in the summer shoulder season (May, September, October). The behavioural response is as expected in most periods – the Super-Peak Scenario On-Peak price (from 7am to 7pm) is lower than both the Status Quo Mid-Peak and Status Quo On-Peak price, leading to an increase in consumption in these periods. The slight reduction in consumption in the early evening Off-Peak is due to cross-price effects – the reduced price during the day resulted in a mild shift of demand from the evening Off-Peak to the Super-Peak Scenario On-Peak period.

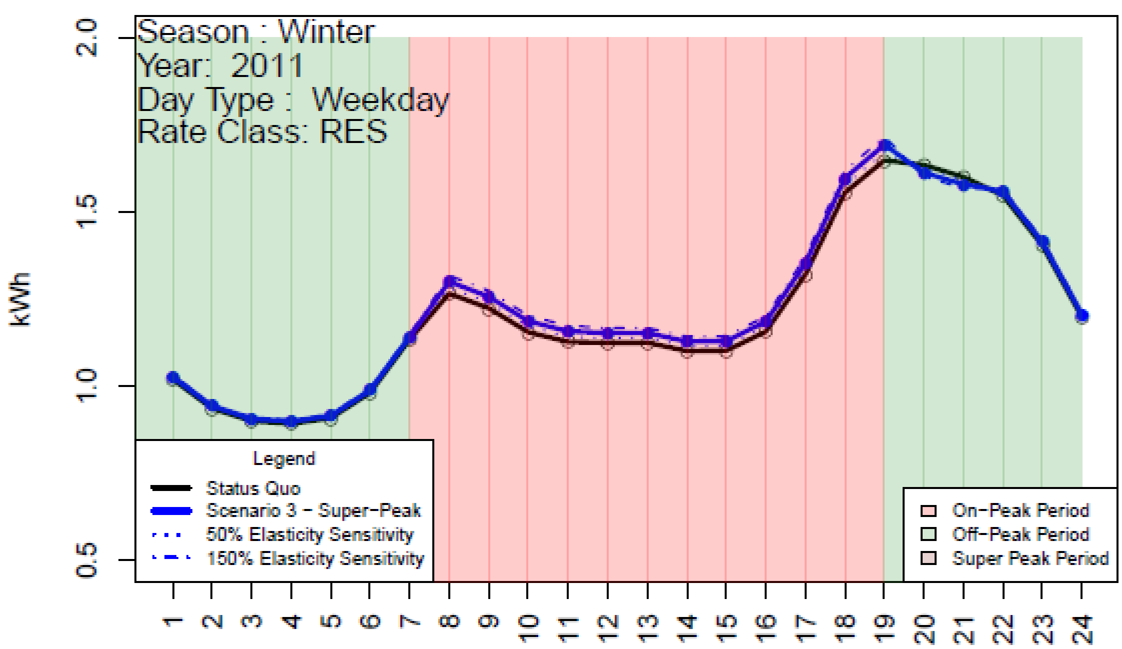
Figure 25: Super-Peak Scenario Residential Summer Shoulder Profile



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 26 shows the residential behaviour impact of the Super-Peak Scenario in the winter (December, January, and February) months. As in the summer shoulder, the reduced cost of day-time electricity has led to an increase in consumption in this period, as well as a reduction (due to cross-price effects) in consumption in the early evening.

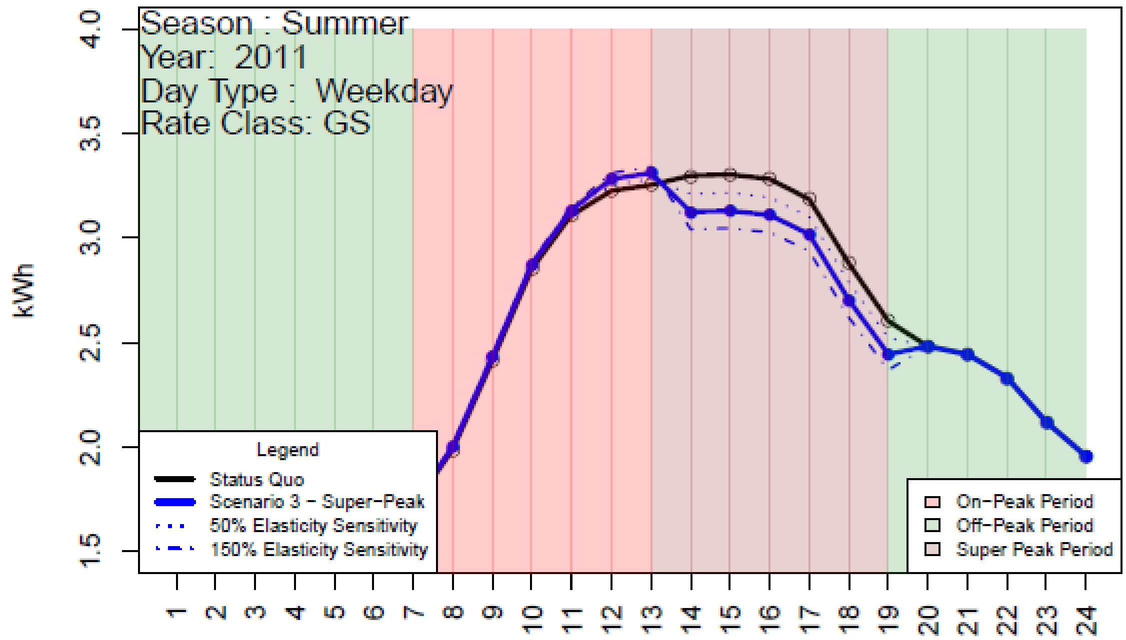
Figure 26: Super-Peak Scenario Residential Winter Profile



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 27 shows the GS behaviour impact of the Super-Peak Scenario in the summer months. With no cross-price effects assumed, impacts are relatively straightforward – in periods where the price has increased consumption has fallen and vice versa. Where the price changes have been relatively small, so too have been the impacts.

Figure 27: Super-Peak Scenario GS Summer Profile



Source: OEB-provided hourly consumption data and Navigant analysis

5.1.4 Scenario 4: Status Quo with Critical Peak Day Prices

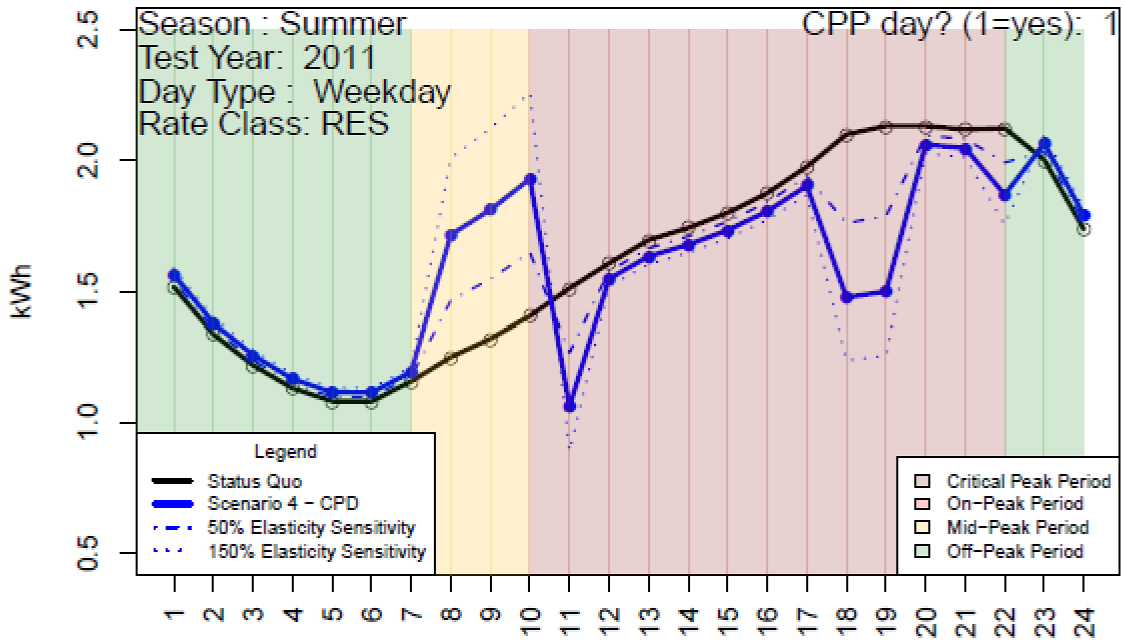
This sub-section provides plots describing the estimated impact of the CPD Scenario prices on customers participating in the CPD Scenario program and responding as indicated by the estimated elasticities. Recall that for this scenario, participating customers are subject to a critical peak price from 10am to 10pm on five days in the summer. In exchange they pay less during the summer Mid-Peak and On-Peak periods. In the winter all prices are identical to those of the SQ.

Note that these responses are for an average participant on the CPD rate – impacts at the system level will not be nearly so extreme since only 5% of residential customers and 2.5% of GS customers are assumed to participate in the program.

Figure 28 shows the residential behaviour impacts of the CPD Scenario on critical peak days, for an average participant. Although impacts are directionally as expected, the magnitude of the impacts is surprising given the results observed above for Super-Peak Scenario. Recall that the critical peak day price for CPD Scenario is 30 cents per kWh, approximately the same as the summer Super Peak price in the Super-Peak Scenario. As above, the black line represents Status Quo average consumption, the blue line represents the scenario average consumption (i.e., after behaviour change) and the narrow dotted and dash-dotted lines represent the scenario average consumption if elasticities are 50% of those estimated or 150% of those estimated, respectively.

As it turns out, the reason why the magnitude of the impact is lower than expected is a function of the test year used, specifically it is an indirect function of the underlying system load profile. Compare the test year 2011 impacts shown in Figure 28 with those for test year 2012, as shown in Figure 29.

Figure 28: CPD Scenario Residential Summer Critical Peak Day Profile – Test Year 2011

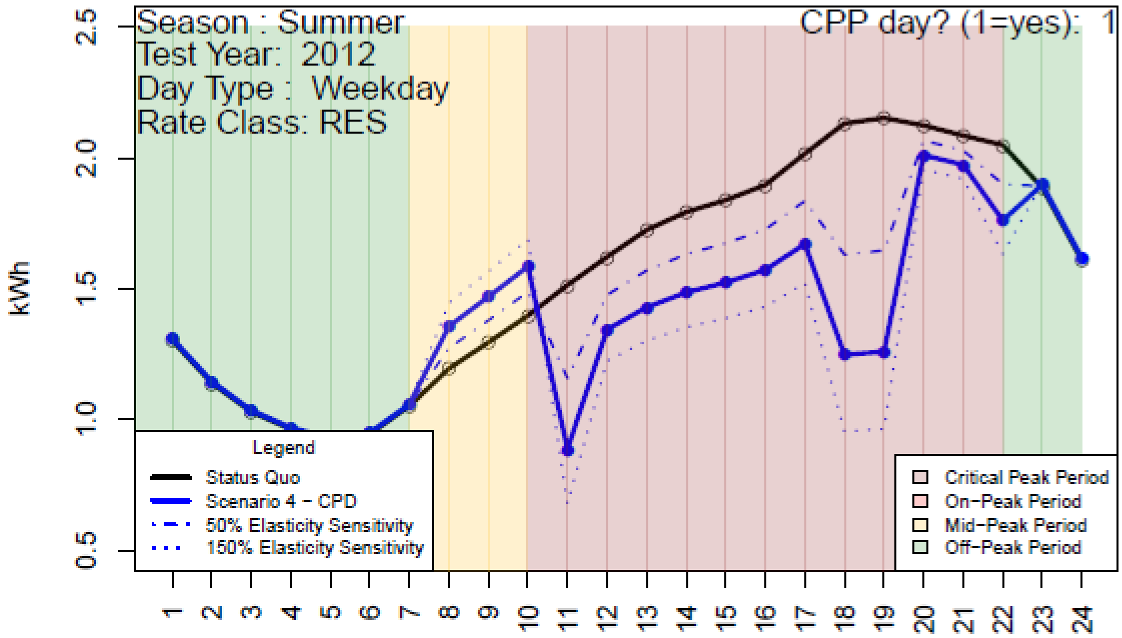


Source: OEB-provided hourly consumption data and Navigant analysis

As may clearly be seen, in test year 2012 (Figure 29) there is a much greater consumption reduction during the critical peak period and a much lower "pre-cooling"[37] impact than in test year 2011.

[37] It is obviously impossible to know what end use is driving the shifted consumption to the earlier period, but the most reasonable explanation for such a shift would be pre-cooling.

Figure 29: CPD Scenario Residential Summer Critical Peak Day Profile – Test Year 2012



Source: OEB-provided hourly consumption data and Navigant analysis

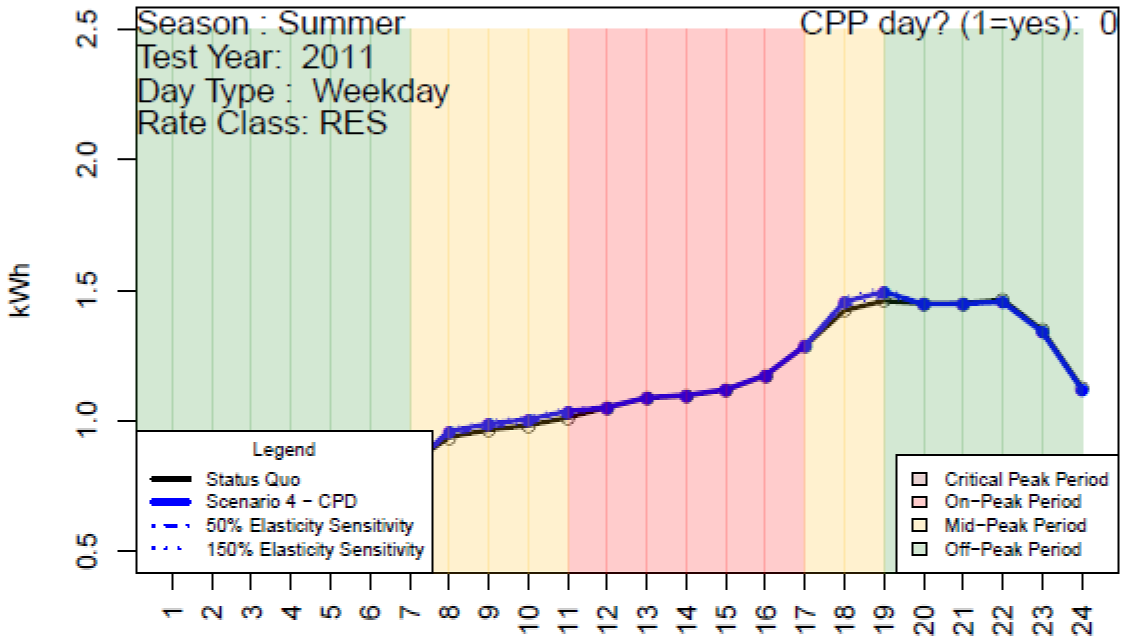
The large difference has to do with the manner in which impacts are calculated and the underlying system load profile that determines which days in the summer are chosen as critical peak days.

Recall, from the equation in 4.1.1, that while own-price effects are calculated based on an individual hourly price, the cross-price effects are calculated based on the *weekly average* price observed in each price period. Recall as well that critical peak days are defined as the top five highest system demand days in a year. As it turns out, in 2011, the top five demand days of the year *all occurred in the same week*. That is, the top five demand days in 2011 were: July 18th, 19th, 20th, 21st, and 22nd.[38] This means that for the CPD Scenario in test year 2011 electricity prices were extremely high (relative to the Status Quo) between 10am and 10pm for the entire week. This greatly dampens the cross-price consumption reduction effect – (since the alternative periods on other days within the week in which electricity could be consumed all have very high prices) but greatly increases the cross-price "pre-cooling" effect (since there are so few relatively low-price periods to which consumption can be shifted). The result is as shown in Figure 28.

The result of having all five high demand days in the same week may also be clearly seen when examining the average residential consumption impact on summer days where there is no CPD event. Compare Figure 30 and Figure 31, plots of residential consumption on summer non critical peak days for test year 2011 and 2012 respectively. Recall that, in exchange for agreeing to participate in the CPD program, participants are given a ~10% discount on their Mid-Peak and On-Peak rates.

[38] The peak day was July 21.

Figure 30: CPD Scenario Residential Summer NON CPD Day Profile – Test Year 2011

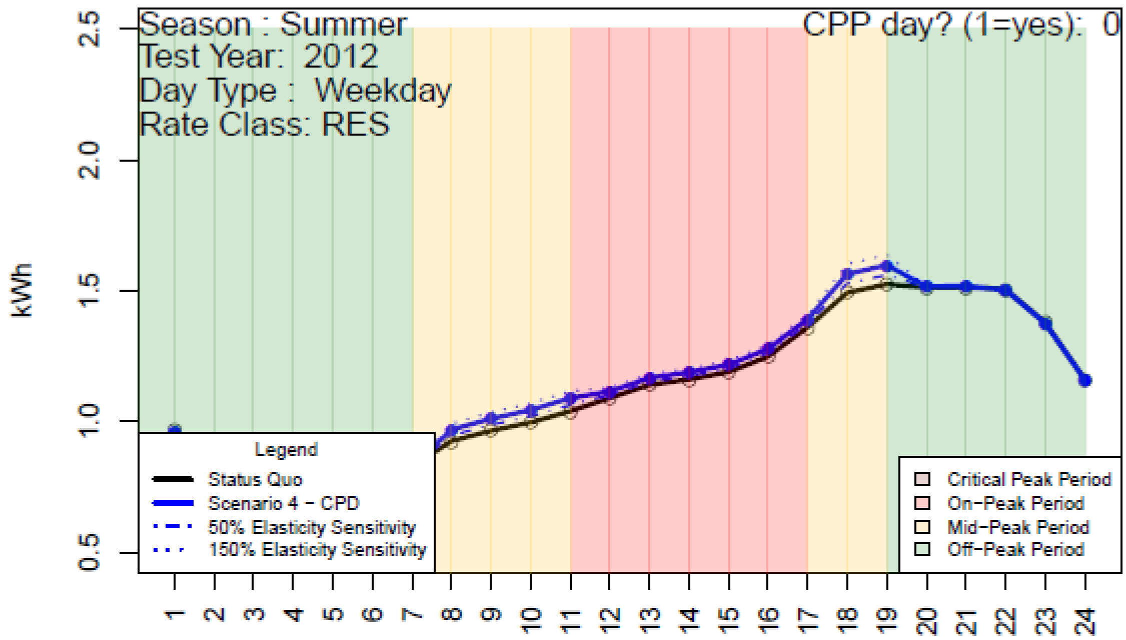


Source: OEB-provided hourly consumption data and Navigant analysis

Note that in Figure 30 there is a very mild increase in consumption during the Mid-Peak period but virtually none during the On-Peak period. In Figure 31, however, there is a significant increase in consumption across both Mid-Peak and On-Peak periods. Since in 2011 all critical peak days occur in a single week, Figure 30 does not capture any inter-daily shifting as a result of critical peak days. It shows only the average behaviour response to the discounted On-Peak and Mid-Peak prices. Figure 31, however, captures the impact of the discount *and* of inter-day (i.e., intra-week) shifting as a result of the very high CPD prices.

In test year 2012 of the CPD Scenario, the average level of consumption on non-CPD days is higher than in test year 2011 because customers are able to shift some of consumption from a critical peak day to a non-critical peak day in the same week. This is not possible for test year 2011 since all critical peak days occur in the same week, and the model does not assume customers can shift consumption between weeks, only between days within a given week.

Figure 31: CPD Scenario Residential Summer NON CPD Day Profile – Test Year 2012



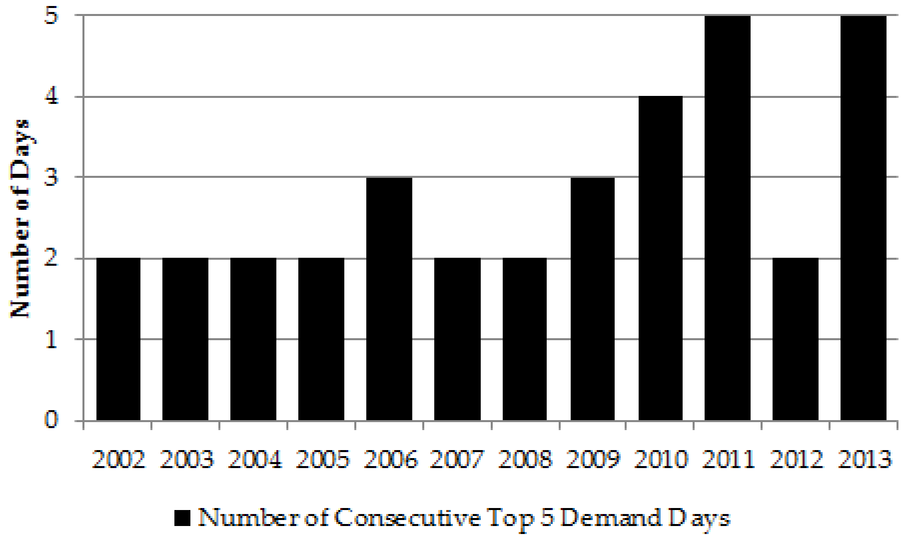
Source: OEB-provided hourly consumption data and Navigant analysis

This effect is in some ways an artefact of the modeling approach – if the cross-price effects were calculated using average monthly, instead of average weekly values the modeled behaviour impacts may be more similar for 2011 and 2012.

Indeed, the effect noted above, even though it is driven by model assumptions, has a very intuitive interpretation: if all critical peak events are called in very close proximity to one another, customers may, through exhaustion or frustration, no longer be as able to respond to them as well as when critical peak days are isolated special events.

This unexpected nuance must be carefully borne in mind by policy makers considering implementing a critical peak day program where event days are driven by system peak; the "clustering" of system peak days appears to have become increasingly common in the last three years – the top five system peak days all occurred in the same week in 2013 as well as 2011, and 2010 saw four of the top five days in a single week. Figure 32 shows the maximum number of top five system demand days occurring in any given week. Note the apparent trend toward peak day clustering that begins in 2009. Speculating on the drivers of this apparent trend is beyond the scope of this report, but if such a trend *is* real, the implication is that it could greatly reduce the effectiveness of a CPD program's impacts on system peak demand.

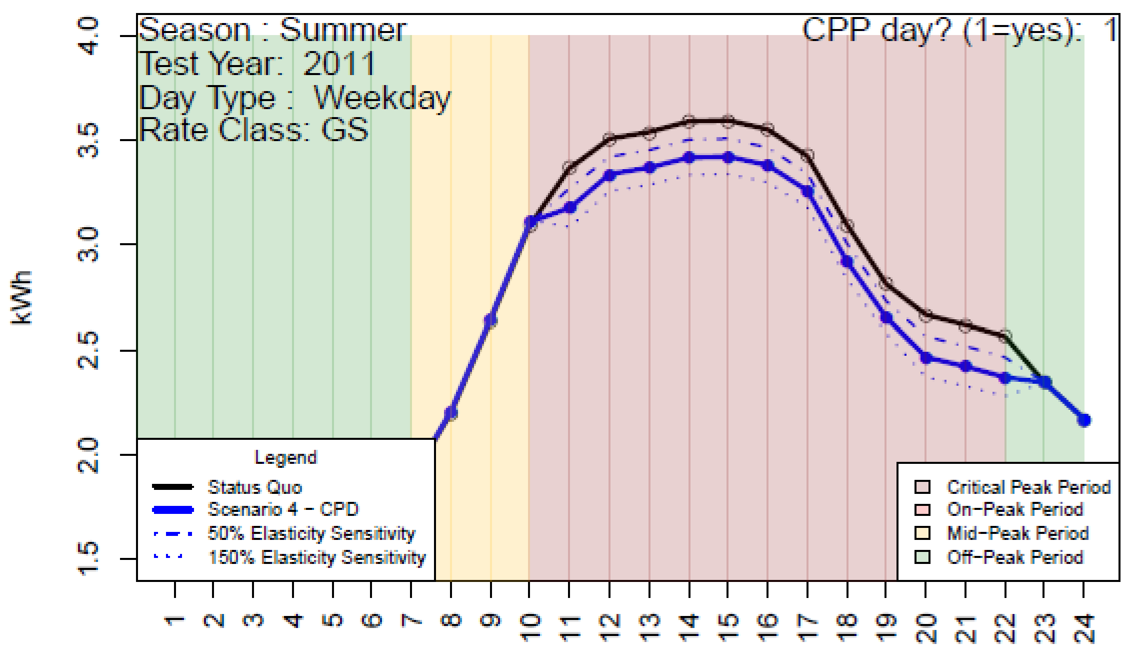
Figure 32: Maximum Number of Peak Days in a Single Week



Source: IESO

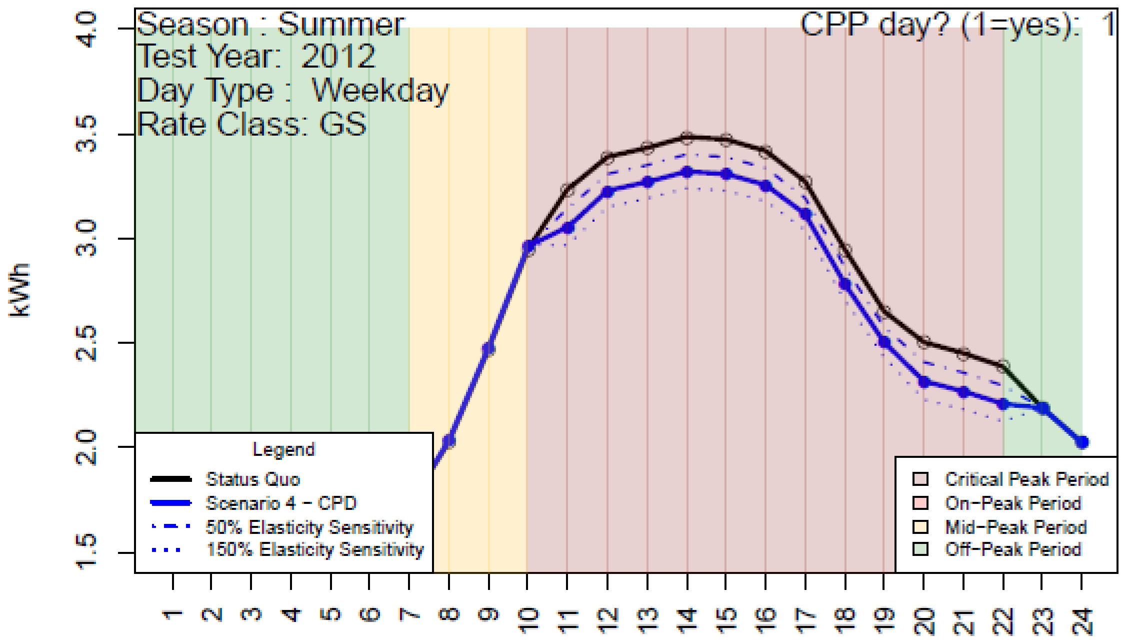
Since no cross-price effects are considered for GS customers, the fact that all critical peak events occur in the same week has no significant impact on the average GS participant's response to critical peak prices from year to year. As may be seen by comparing Figure 33 with Figure 34 the impacts (which are in line with expectations) are nearly identical in both test year 2011 and test year 2012.

Figure 33: CPD Scenario GS Summer Critical Peak Day Profile – Test Year 2011



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 34: CPD Scenario GS Summer Critical Peak Day Profile – Test Year 2012



Source: OEB-provided hourly consumption data and Navigant analysis

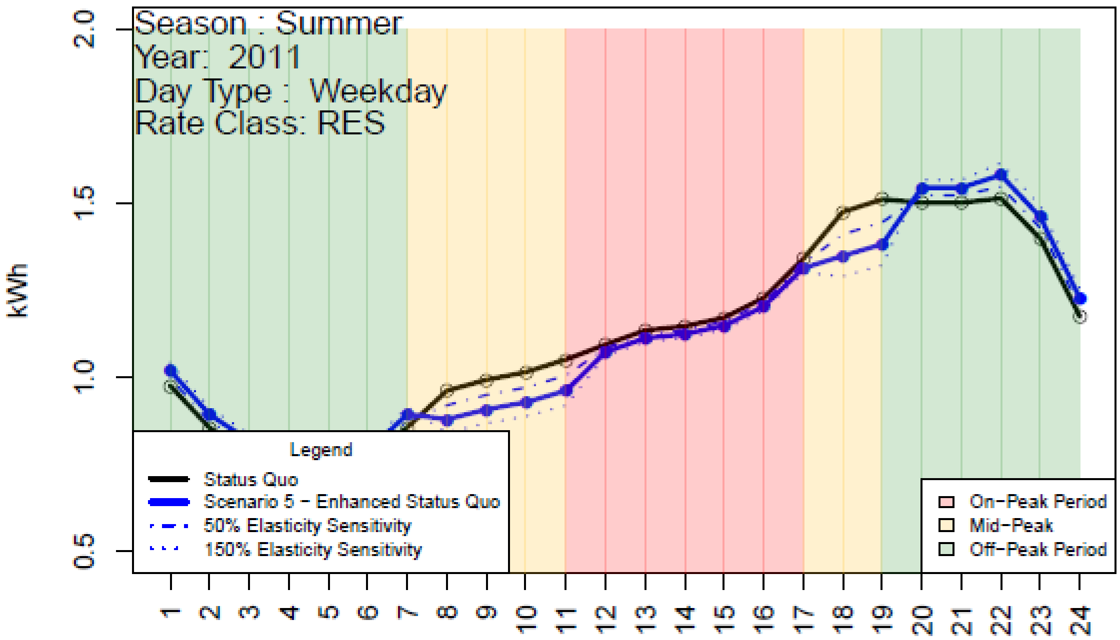
5.1.5 Scenario 5: Enhanced Status Quo

This sub-section provides plots describing the estimated impact of the ESQ Scenario prices on electricity consumption. Recall that in the ESQ Scenario, all TOU periods are identical to the Status Quo, with only the prices differing; the Off-Peak price is lower than in the Status Quo, whereas the Mid-Peak and On-Peak prices are higher.

Figure 35, below, shows the residential behaviour impacts of the ESQ Scenario on summer weekdays, for an average customer. Note that maintaining a differential between the On-Peak and Mid-Peak prices means there is no undesirable cross-price effect as there was in the Flat Scenario where consumption during the Status Quo On-Peak period (11am to 5pm) increased despite the price also increasing. In this case the net effect of the scenario price changes has been to shift consumption away from the 7am – 7pm window, as would be expected given the increase in prices in that period.

As above, the black line represents Status Quo average consumption, the blue line represents the scenario average consumption (i.e., after behaviour change) and the narrow dotted and dash-dotted lines represent the scenario average consumption if elasticities are 50% of those estimated or 150% of those estimated, respectively.

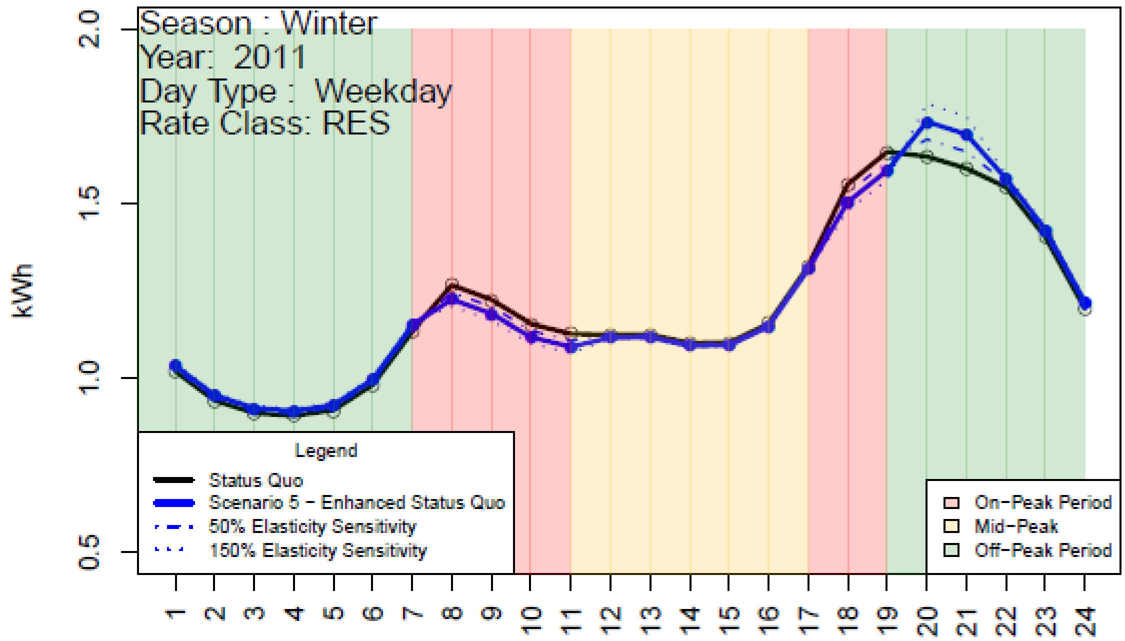
Figure 35: ESQ Scenario Residential Summer Profile – Test Year 2011



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 36, below, shows the residential behaviour impacts of the ESQ Scenario on winter weekdays, for an average customer. As for summer, the net result is a shifting of consumption away from the 7am to 7pm window and toward the Off-Peak periods. Note that winter behaviour impacts are smaller than those estimated for the summer due to the correspondingly more modest elasticities estimated for the winter.

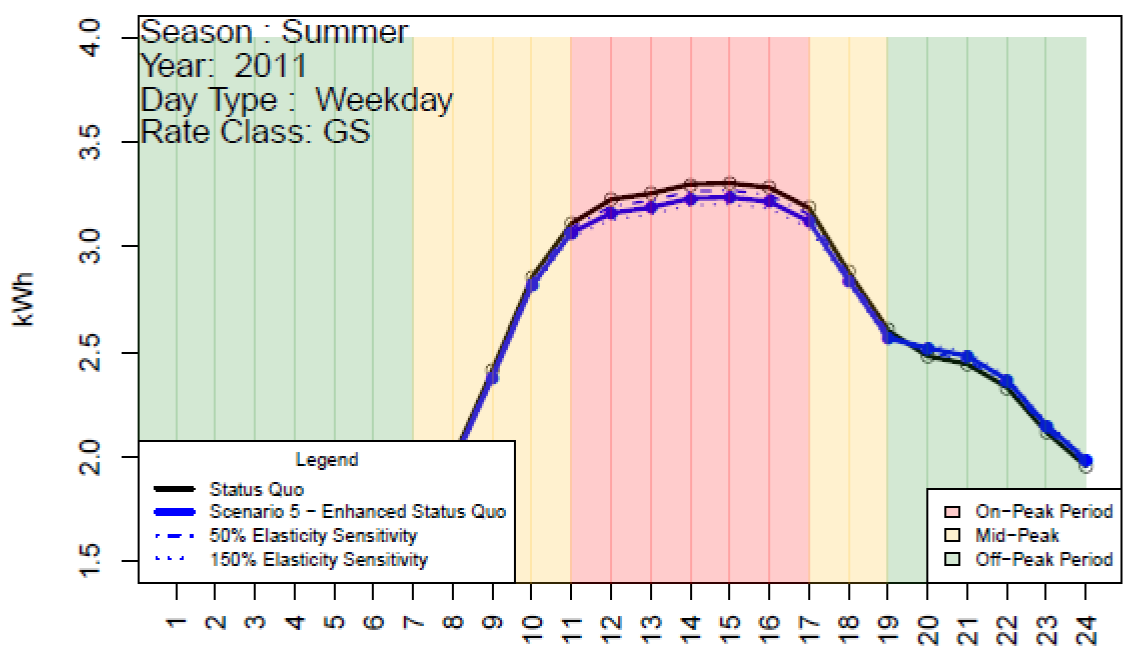
Figure 36: ESQ Scenario Residential Winter Profile – Test Year 2011



Source: OEB-provided hourly consumption data and Navigant analysis

Figure 37, below, shows the GS behaviour impacts of the ESQ Scenario on summer weekdays, for an average customer. The impact is as expected, with consumption falling during the Mid-Peak and On-Peak periods (in which prices have increased) and increasing slightly in the Off-Peak period (in which the price has fallen). Recall that GS impacts reflect only own-price and no cross-price effects.

Figure 37: ESQ Scenario GS Summer Profile – Test Year 2011



Source: OEB-provided hourly consumption data and Navigant analysis

5.2 System Peak Demand Impacts

This section provides a summary of the impact of each scenario on system peak demand and provides plots of the Status Quo and scenario system-level demand on peak days and discusses the results and some possible implications.

As noted above, this metric makes use of forecast 2013 system consumption and test year 2011 and 2012 system profiles. Navigant has also explored how sensitive the peak demand impact provoked by each price scenario is to a change in the underlying system demand profile. In Appendix C, Navigant has re-estimated peak demand impacts using a system demand profile that reflects the Ministry of Energy's *Long Term Energy Plan*'s forecast of solar PV by the year 2020. This alternative system load profile has a considerable effect on the estimated peak demand impacts and should be examined by readers interested in the potential impact of the scenarios outlined in this report when solar PV production has increased substantially.

Figure 38 shows the impact on system peak demand[39] for each scenario and each test year, as well as the average impact across both test years. A negative number indicates a net demand reduction, whereas a positive number indicates a net increase in system peak demand. Figure 38 also shows the relative rank assigned to each scenario, based on the system peak MW impacts. A scenario ranked as "1" is the "best" scenario, and a scenario ranked as "5" is the "worst".

Figure 38: Estimated System Peak Demand Impact (MW)

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	-20	197	464	-47	-118
2012	-58	229	619	-99	-218
Average	**-39**	**213**	**542**	**-73**	**-168**
Rank:	**3**	**4**	**5**	**2**	**1**

NB: assumes 5% residential and 2.5% GS participation for the CPD and CPP Scenarios

Source: OEB-provided hourly consumption data and Navigant analysis

As expected, given the behaviour impacts estimated in 5.1.2, above, the Flat Scenario increases peak demand. Recall that the substantial price increase in the Status Quo Mid-Peak period (7am to 11am and 5pm to 7pm, summer) led to consumption being shifted from that period to the Status Quo On-Peak period (11am to 5pm, summer) despite prices also increasing in that period. This has the effect of increasing residential demand from 11am to 5pm on summer weekdays, increasing system peak demand.

39 Defined as the average demand over the top ten demand hours of the year.

Also, as expected, the CPP Scenario and the CPD Scenario result in a decrease in peak demand. The difference in impact by test year is a result of the clustering of critical peak events in 2011 reducing customers' ability to shift critical period. This effect is substantial – demand reductions (net of "pre-cooling" and "snapback" [40] effects) in test year 2012 are twice what they are in test year 2011 for the CPD Scenario and three times what they are in 2011 for the CPP Scenario.

The impact for the Super-Peak Scenario is surprising. This scenario results in an average increase of system peak demand of more than 500 MW. The reasons for this will be discussed below.

The peak demand reduction achieved by the ESQ Scenario is as expected given the results above: increasing Mid-Peak and On-Peak prices (but maintaining a differential between them) and decreasing Off-Peak prices has resulted in consumption being shifted away from the 7am to 7pm window, reducing peak demand.

The remainder of this section is divided into four sub-sections, one for each scenario. Each sub-section provides plots of system impact in each test year and some discussion of the results.

5.2.1 Scenario 1: Status Quo with CPP Prices

The CPP Scenario is a voluntary participation scenario: only program participants are subject to the critical peak prices and the corresponding discounts in other periods. Navigant has, as discussed in 4.1.3, assumed a base participation rate in this scenario of 5% of residential customers and 2.5% of GS customers.

To test the sensitivity of results to these assumptions, Navigant has also estimated system demand impacts where participation is twice the base rate and where it is four times the base rate. The estimated impacts for the base participation case and for the sensitivity cases are shown in Figure 39, below.

Figure 39: System Demand Impact by Test Year and Participation Rate (MW)

Test Year	Base Participation	2x Base Participation	4x Base Participation
2011	-20	-34	-9
2012	-58	-100	-136
Average	**-39**	**-67**	**-73**

Source: OEB-provided hourly consumption data and Navigant analysis

Note that in Figure 39 for test year 2012 the system peak demand impact behaves more or less as would be expected in the sensitivity cases – as participation rates increase, so too do demand savings (albeit at a decreasing rate). Test year 2011 results, however show that at the highest level of

40 "Snapback" refers to an increase in electricity demand immediately following a critical peak pricing or direct load control event that may be attributable to that event.

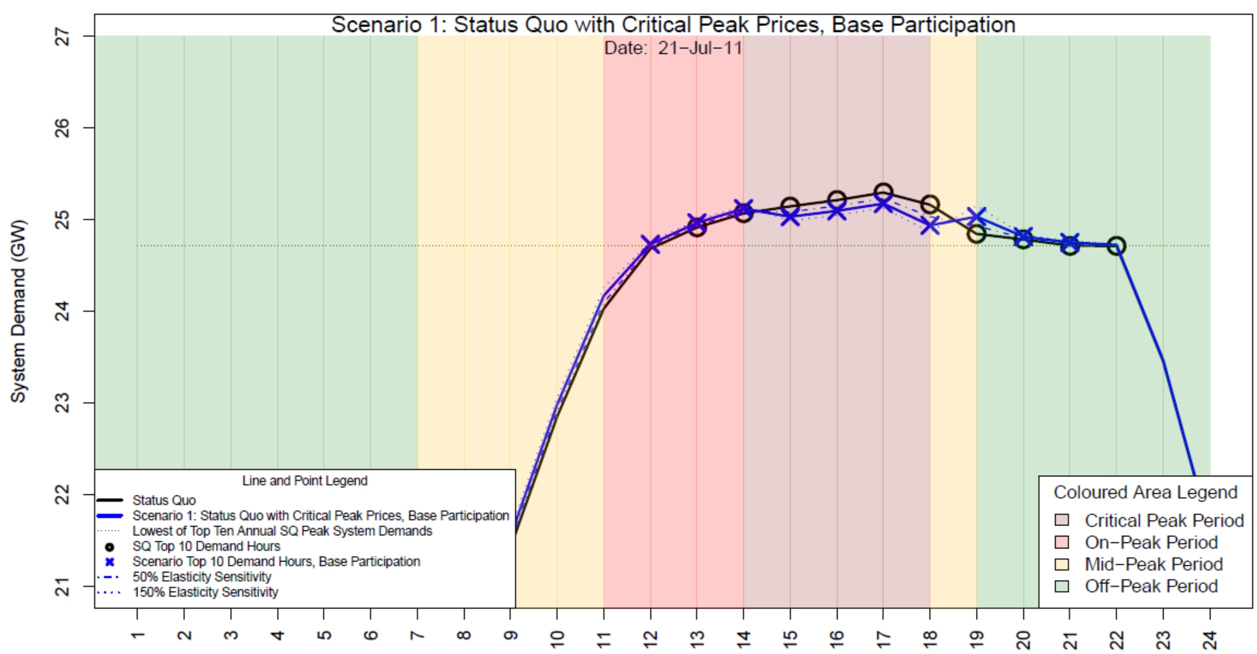
participation tested, the peak demand impact is actually less than that estimated using the base participation levels. This disparity is driven by the fact that in 2011 every day of the week in which the system peak occurred has a critical peak event.

The results of this effect, when compounded by higher than base levels of participation, may be seen by comparing plots of the CPP Scenario Ontario demand on the peak system day of 2011 for both the base and the highest participation sensitivity case. Figure 40 shows Status Quo and The CPP Scenario (base participation) hourly demand on the system peak day for test year 2011. The top ten demand hours are indicated by the markers – circles for Status Quo peak demand hours and crosses for the CPP Scenario peak demand hours. In test year 2011 all ten Status Quo peak demand hours take place on July 21.

As above the narrow dotted and dash-dotted lines represent the scenario average consumption if elasticities are 50% of those estimated or 150% of those estimated, respectively.

Note in Figure 40 the shifting of demand away from the critical peak hours (2pm to 6pm) to the hours immediately before and after that period. Although the net effect is to reduce average peak demand over the top ten hours, there are some the CPP Scenario top ten hours that have higher levels of demand 1 than under the Status Quo.

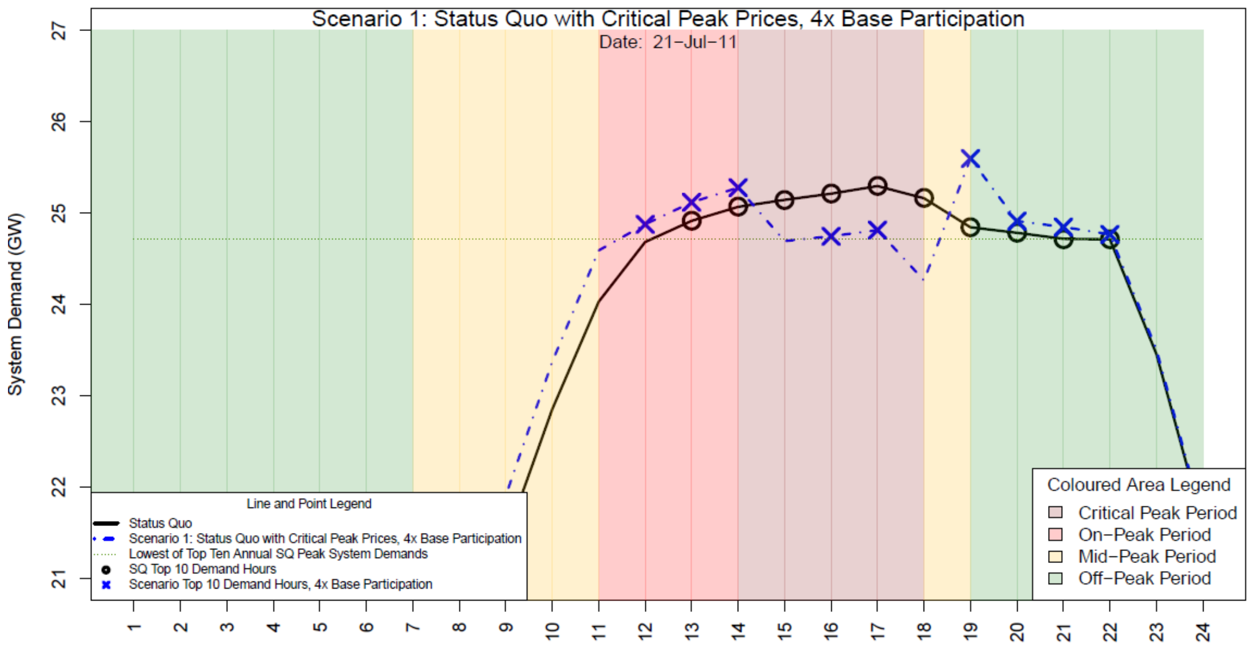
Figure 40: System Peak Demand, the CPP Scenario, Base Participation, Peak Demand Day 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Now, consider Figure 41, below. In this case the CPP Scenario has four times the assumed base participation (20% of residential and 10% of GS customers participating). Note that due to shifting, there is an hour (hour ending 12 – 11am to noon) in the CPP Scenario that is in the top ten demand hours for that scenario but that was not for the Status Quo. Although the net effect is still a reduction in peak demand, the increased system-wide levels of "pre-cooling" and "snapback" are such that the impact is much less than under the base participation assumption.

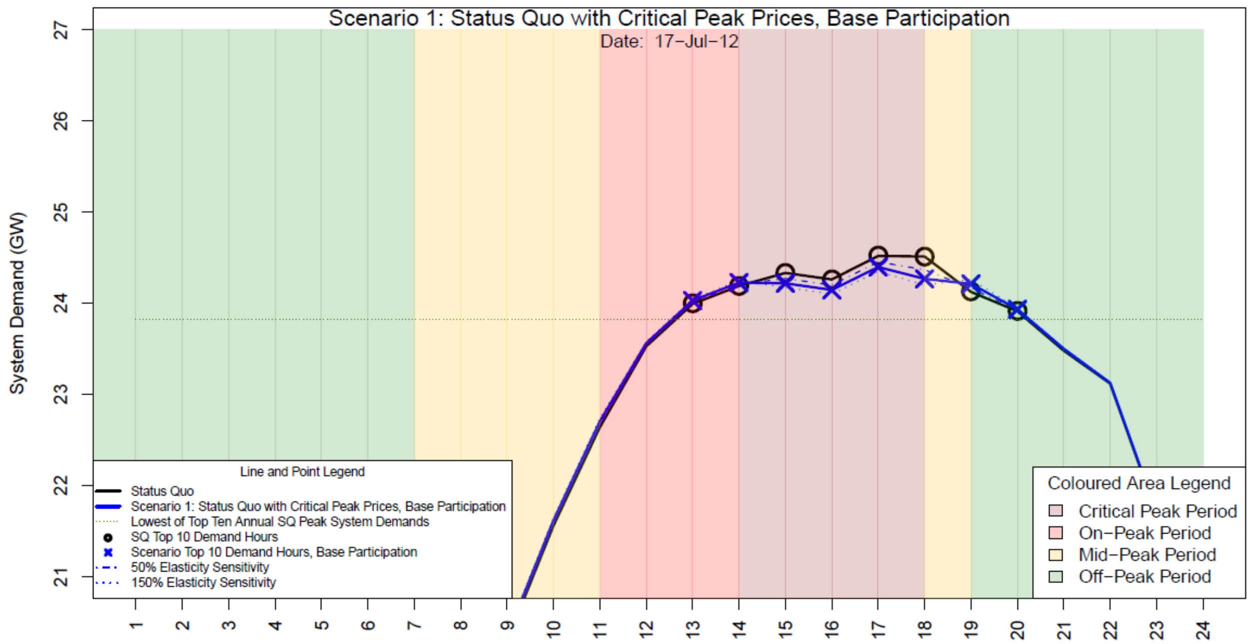
Figure 41: System Peak Demand, the CPP Scenario, 4x Base Participation, Peak Demand Day 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

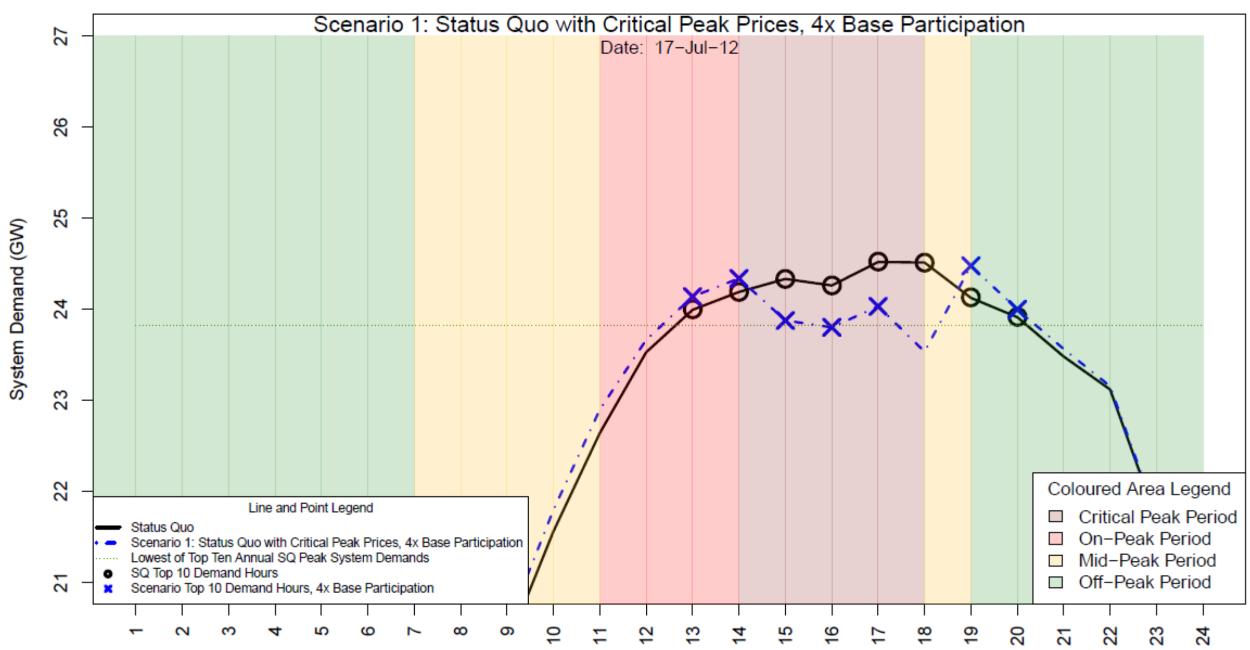
Figure 42 and Figure 43, show the Status Quo and the CPP Scenario hourly peak demand for base participation and four times base participation, respectively. A comparison of test year 2012's sensitivity plot (Figure 43) with that of test year 2011 (Figure 41) clearly shows the smaller level of "pre-cooling" and "snapback" in test year 2012 due to critical peak events being less clustered.

Figure 42: System Peak Demand, the CPP Scenario, Base Participation, Peak Demand Day 2012



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 43: System Peak Demand, the CPP Scenario, 4x Base Participation, Peak Demand Day 2012



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

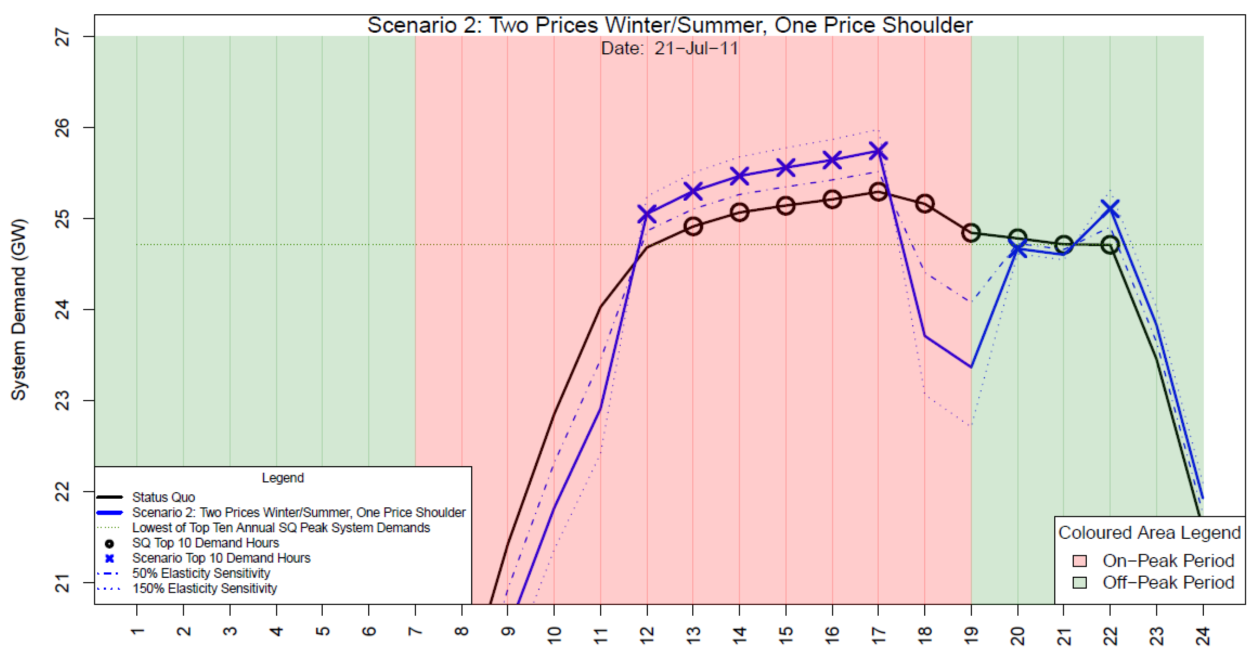
5.2.2 Scenario 2: Two Prices Winter/Summer, One Price Shoulder

The Flat Scenario is a mandatory scenario – it is assumed that all residential and GS RPP customers will be required to participate.

Figure 44 shows the hourly system demand on the 2011 peak demand day under the Status Quo and the Flat Scenario. As described in 5.1.2, above, the Flat Scenario results in an increase in consumption during the Status Quo On-Peak period (11am to 5pm), despite the price in that period increasing. This is due to cross-price effects that drive customers to shift consumption from the Status Quo Mid-Peak period (7am to 11am and 5pm to 7pm) to the Status Quo On-Peak period (11am to 5pm) due to the relatively higher increase in prices in the Status Quo Mid-Peak period (7am to 11am and 5pm to 7pm).

Although for test year 2011 the Flat Scenario does result in a relatively substantial reduction in demand in two of the Status Quo top ten demand hours, (hours ending 18 and 19, see Figure 44), this is more than offset by the increase in demand in the other Status Quo top ten demand hours and the increase in demand in hours that were not top ten demand hours in the Status Quo but become so in the Flat Scenario (see Figure 45).

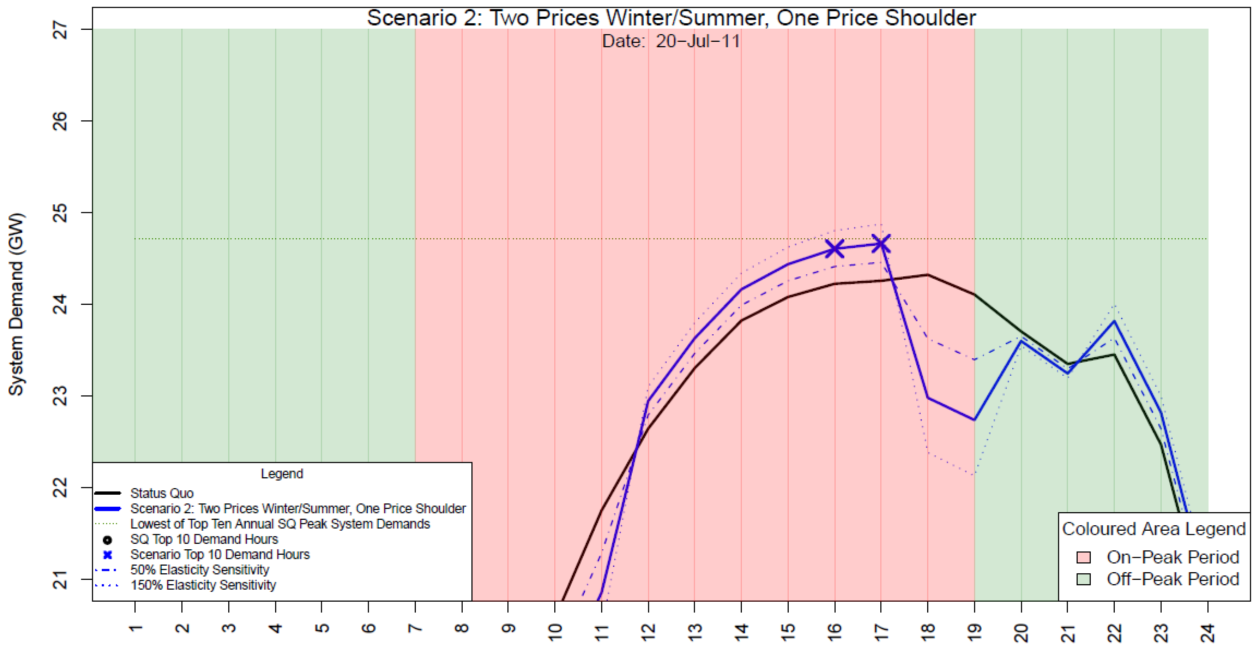
Figure 44: System Peak Demand, the Flat Scenario, Base Part., Top Peak Demand Day 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Overall, this results in the Flat Scenario increasing peak demand, as show in the summary table, Figure 38, above.

Figure 45: System Peak Demand, the Flat Scenario, Base Part., Second Peak Demand Day 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

5.2.3 Scenario 3: Summer Super Peak

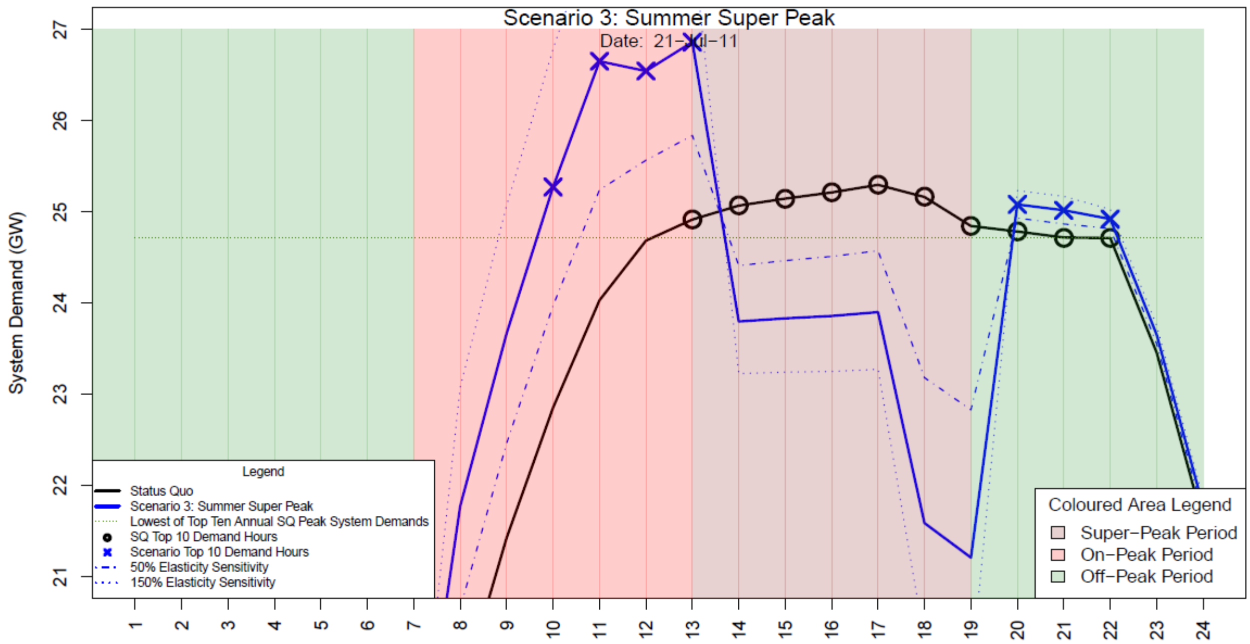
The Super-Peak Scenario is a mandatory scenario – it is assumed that all residential and GS RPP customers will be required to participate. Figure 38, the table in the introduction to this section, indicated that this scenario performed the worst, in terms of reducing system peak. Based on the elasticities estimated in Part 1 of this study, in fact, Navigant's modeling suggests that this scenario could result in an *increase* in system peak demand.

This is due to the modeled "pre-cooling" and "snapback" impacts that significantly increase system demand in hours that, in the Status Quo, were not in the top ten demand hours to levels above those observed in the Status Quo top ten demand hours.

This "squeezing" effect occurs not just on the peak demand day (see Figure **46**) but also on days that, in the Status Quo, did not have *any* of the top ten demand hours. Note, for instance Figure **47** and Figure **48**, where the pre-cooling impact has resulted in an hour (or two) on each of those days falling into the top ten demand hours when in the Status Quo none of the hours fell into the top ten demand hours.

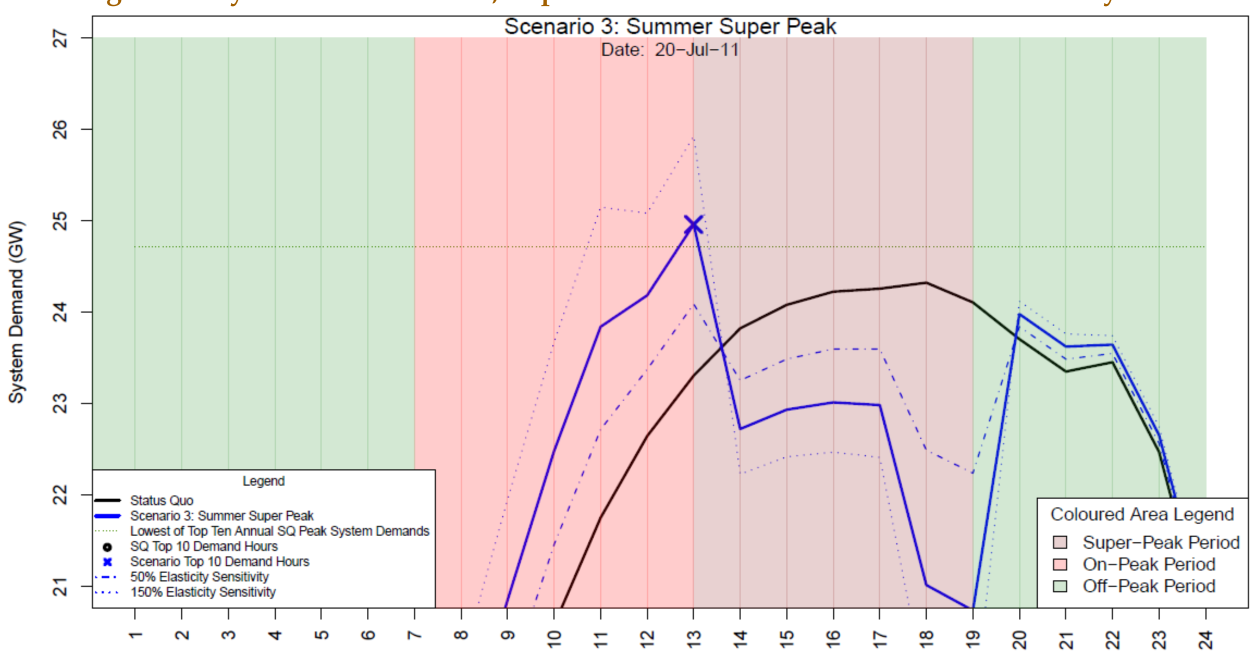
These increases in system peak demand erode the substantial demand impact realized in the afternoon of the peak day and result in a net increase in peak demand, as it is defined for this study.

Figure 46: System Peak Demand, Super-Peak Scenario Top Peak Demand Day 2011



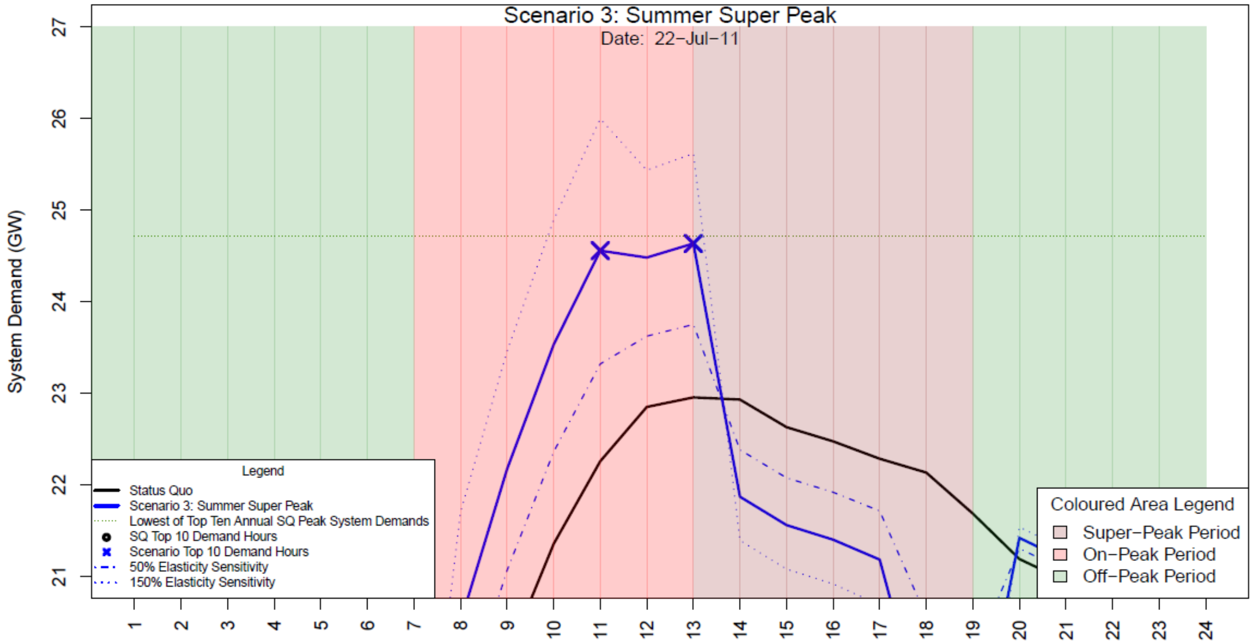
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 47: System Peak Demand, Super-Peak Scenario Second Peak Demand Day 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 48: System Peak Demand, Super-Peak Scenario Third Peak Demand Day 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

5.2.4 Scenario 4: Status Quo with Critical Peak Day Prices

the CPD Scenario is voluntary participation scenario: only program participants are subject to the critical peak prices and the corresponding discounts in other periods. Navigant has, as discussed in 4.1.3, assumed a base participation rate in this scenario of 5% of residential customers and 2.5% of GS customers.

To test the sensitivity of results to these assumptions, Navigant has also estimated system demand impacts where participation is twice the base rate and where it is four times the base rate. The estimated impacts for the base participation case and for the sensitivity cases are shown in, below.

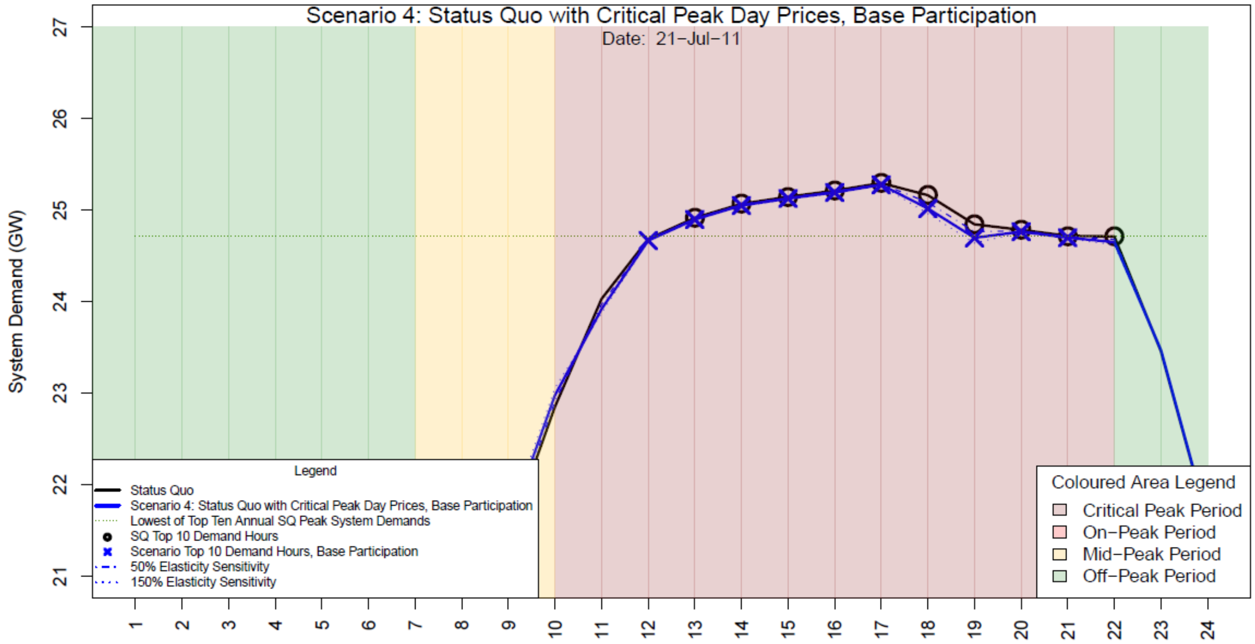
Figure 49: System Demand Impact by Test Year and Participation Rate

Test Year	Base Participation	2x Base Participation	4x Base Participation
2011	-47	-87	-158
2012	-99	-193	-348
Average	**-73**	**-140**	**-253**

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure **50** shows system hourly demand under the Status Quo and the CPD Scenario with base assumed participation on the top demand day for 2011, July 21.

Figure 50: System Peak Demand, the CPD Scenario, Base Participation, Peak Demand Day 2011

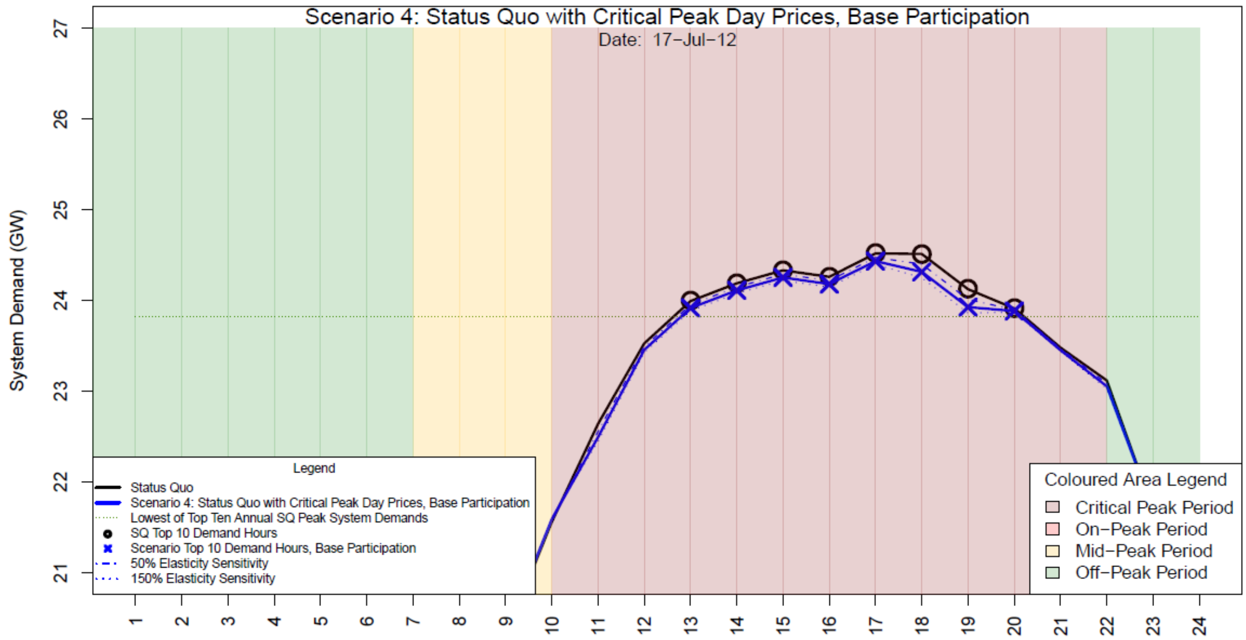


Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Due to all five of the top demand days falling in the same week, the demand reduction impacts are relatively mild, almost imperceptible in Figure **50**. The impacts may be more clearly seen in Figure **51**, which shows the hourly demand of both Status Quo and the CPD Scenario (with base participation) in test year 2012.

Unlike the CPP Scenario, the critical peak period covers all of the hours in which the top ten Status Quo demand hours fall. This means that "pre-cooling" and "snapback" effects occur outside the range of the Status Quo top ten demand hours. The fact that participation is voluntary means that there is no massive "pre-cooling" impact that shifts the top ten demand hours to earlier in the day. The net result is the most substantial peak demand reduction of any of the scenarios.

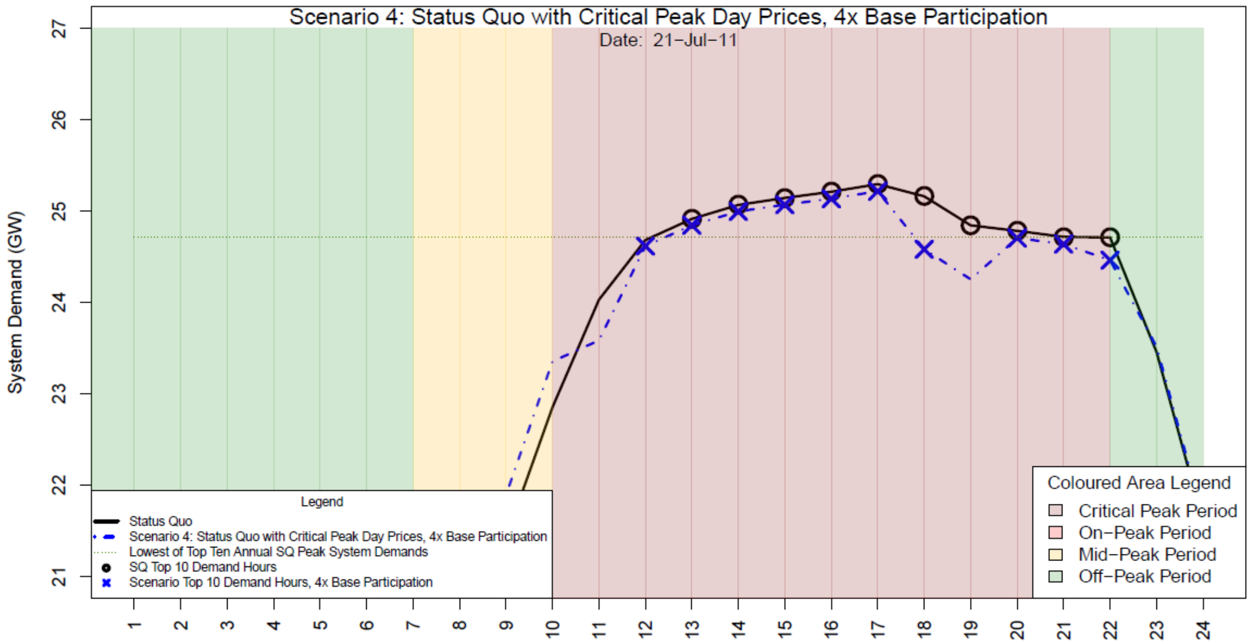
Figure 51: System Peak Demand, the CPD Scenario, Base Participation, Peak Demand Day 2012



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Even as participation increases to four times the base assumed level, there is no "take-back" of demand impacts, as found for the CPP Scenario. This is principally because of the length of the critical peak period, which pushes "pre-cooling" effects sufficiently early that they do not create new top ten demand hours. This can be seen in Figure 52, which shows the highest participation sensitivity case for the test year 2011 peak day.

Figure 52: System Peak Demand, the CPD Scenario, 4x Base Participation, Peak Demand Day 2011



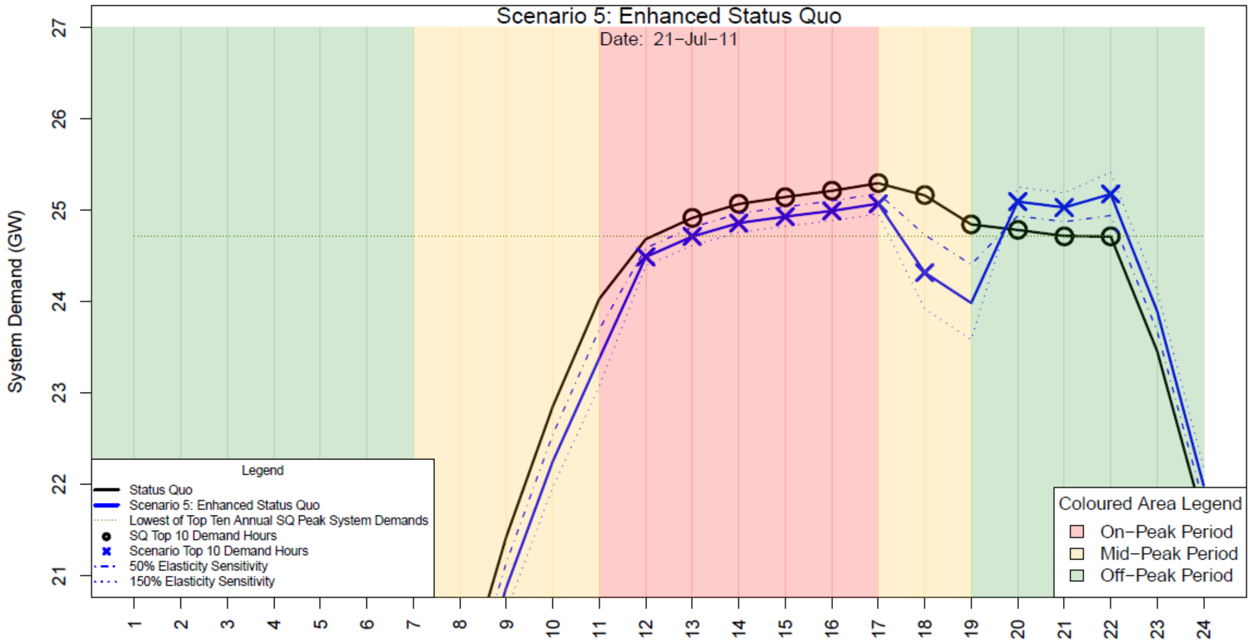
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

5.2.5 Scenario 5: Enhanced Status Quo

the ESQ Scenario is a mandatory scenario – it is assumed that all residential and GS RPP customers will be required to participate. Figure 38, the table in the introduction to this section, indicated that this scenario performed the best, in terms of reducing system peak, resulting in a reduction in peak demand of between 118 and 218 MW, depending on the test year.

It is immediately clear when examining Figure 53, below, that the impact of the the ESQ Scenario prices is such to reduce demand considerably during the majority of the system peak demand hours on the "plateau". Like all the other scenarios except the CPD Scenario the fact that the periods of elevated prices (On-Peak and Mid-Peak periods) do not cover the system peak hours in the evening leads to some "take back" of peak demand impacts; the demand reductions from 11am to 7pm are partially offset by demand increases from 7pm to 10pm.

Figure 53: System Peak Demand, the ESQ Scenario Top Peak Demand Day 2011



It should be noted that since this scenario is assumed to be mandatory, normalized for participation this scenario delivers less of a reduction in system peak demand than either the CPP Scenario or the CPD Scenario.

5.3 Ease of Implementation

This section provides the ranking of the five scenarios according to the ease with which Navigant believes they could be implemented in Ontario. Navigant has identified three distinct aspects of implementation that it has addressed within the three sub-sections below:

- Technical Feasibility;
- Public Acceptance; and
- Legal/Regulatory.

Each scenario is assigned a rank for each of these aspects of implementation. The final rank assigned to each scenario for this metric is based on the average of each scenario's aspect-specific ranks. As with the other metrics, the lower the number, the more favourable is the rank.

The overall rank for each scenario, as well as the rank for each aspect of implementation is shown in Figure **54**, below. As may be seen in this table, Navigant believes that the ESQ Scenario would prove to be the easiest of the scenarios to implement on the provincial level and that Scenarios (Super-Peak and 4 (CPD) would be the most difficult. Note that for some implementation aspects, different scenarios may have the same rank where Navigant believes that the difficulty in implementing the two scenarios would not be significantly different.

This metric is qualitative; it is based on Navigant's professional judgement and its interpretation of the relevant legislation, regulation and rules. A complete legal and regulatory analysis of each of the five scenarios is beyond the scope of this study, and Navigant's discussion of these issues should be understood to be a high level interpretation of the issues.

Figure 54: Overall Ranking of Ease of Implementation and by Aspect of Implementation

Implementation Aspect	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Technical Feasibility	4	2	3	4	1
Public Acceptance	1	2	4	1	3
Legal/ Regulatory	1	3	2	4	1
Average Rank	**2**	**3**	**4**	**4**	**1**

Source: Navigant analysis

5.3.1 Technical Feasibility

This sub-section discusses the technical feasibility of the five scenarios. The two principal technical considerations of a provincial roll-out of any alternative TOU structure are:

How significant a change is required for the Meter Data Management and Repository's (MDM/R) management of Smart Meter data; and

How significant a change is required of LDC billing systems.

The MDM/R's current principal role is to collect hourly Smart Meter (SM) data from the LDCs and to in turn provide the LDCs with each customer's level of consumption by TOU period. The LDCs input this information into their billing systems which then multiply the consumption by the TOU commodity charges and other non-commodity volumetric charges for which they are responsible. This allows the LDCs to generate each customer's bill.

In estimating the technical feasibility of each alternative, Navigant has taken the view that in data-intensive applications it is always simpler to aggregate already existing categories than to implement new sets of categories. That is, Navigant believes that it would be simpler for the MDM/R to provide the new, scenario-specific, outputs required by the LDCs if they are "coarser" rather than "finer" than those required under the Status Quo.

If this general principal holds true then it is clear that the Flat Scenario would be the second simplest alternative structure for the MDM/R to implement. Within each month of the year, all of the TOU periods proposed by the Flat Scenario are simply aggregations of existing periods. In the summer and winter, the the Flat Scenario On-Peak encompasses both the Status Quo On-Peak and Mid-peak periods and in the shoulder months, the Shoulder period applies 24 hours a day and seven days a week.

The ESQ Scenario would, of course be the simplest alternative structure for the MDM/R to implement since no change would be required beyond the prices, which change every six months in any case.

A second criterion for assessing the impact of each TOU scenario on data management is predictability. It will be simpler for the MDM/R to output data to LDCs when the TOU periods are seasonally consistent – when they apply in the same hours of the weekday in every day of a season. This means that relatively simple rules can be established for assigning hourly consumption to one or another period, without requiring any new, regular inputs except the SM data itself.

Under this criterion, the CPP Scenario and the CPD Scenario would be the most complicated scenarios for the MDM/R to implement. In addition to both scenarios adding a fourth TOU period (and one which does not fall within the borders of an existing, Status Quo TOU period), both scenarios have an irregular and quasi-random period that is not known until the day before it happens. The critical peak period in both scenarios is fixed in terms of the hours that it covers, but the days on which this period occurs are determined based on a short-term forecast of system demand.

By process of elimination, the Super-Peak Scenario must fall between the Flat Scenario and the two critical peak scenarios, in terms of complexity for the MDM/R.

All alternative TOU scenarios would require changes to LDC billing systems. Even the two voluntary critical peak scenarios (the CPP Scenario and the CPD Scenario) would require changes to the billing system of any LDC that offered the program, even if none of its customers signed up. Navigant is not aware of any compelling reason that would suggest that one scenario would require more complicated billing system changes than any other.

Based on the above, for the "Technical Feasibility" aspect of implementation, Navigant assigned the following ranks to each scenario. Note that the CPP Scenario and the CPD Scenario are tied, both having the "worst" rank.

Figure 55: Scenario Rank for Technical Feasibility

Implementation Aspect	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Technical Feasibility	4	2	3	4	1

Source: Navigant analysis

5.3.2 Public Acceptance

This sub-section discusses the public acceptance of the five scenarios. Navigant has assessed the public acceptance and political viability of each of the proposed scenarios based on two general criteria:

Is the scenario rate compulsory?; and

Is the scenario likely to provoke substantial "sticker shock"?

Navigant is of the view that any alternative TOU rate that is not compulsory will have a high level of public acceptance – after all, if the alternative is business-as-usual, only those that stand to benefit from the rate will likely have a strong view about it and in that case the view will be positive. Based on this criterion, Navigant believes that the CPP Scenario and the CPD Scenario would both be the most publically acceptable and politically viable alternative TOU structures.

Given the simplicity of the rate structure proposed for the Flat Scenario, and the relatively small changes in price (upward and downward), Navigant thinks it likely that this scenario would be the second-most publically acceptable scenario.

Although not as dramatic as the Super-Peak Scenario, the price of the highest-priced period in the ESQ Scenario is almost one and a half times the highest price in the Status Quo. Given this, Navigant thinks it likely that this scenario would be the third-most publically acceptable scenario.

the Super-Peak Scenario, with its very high Super-Peak price that applies in every weekday of the summer would likely generate the most public resistance and controversy. This structure would mean customers would receive a substantial discount for daytime electricity in the non-summer months and morning electricity in the summer months, but because of the length of the of the period in which the discount applies, the change in the absolute unit price (i.e., $/kWh) would look very small compared to the increase in price during the summer Super Peak period. Given the sticker shock aspect of this Scenario, Navigant believes that the Super-Peak Scenario would be least publically acceptable scenario.

Figure 56: Scenario Rank for Public Acceptance

Implementation Aspect	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Public Acceptance	1	2	4	1	3

Source: Navigant analysis

5.3.3 Legal/Regulatory

This sub-section discusses the legal and regulatory hurdles that the five scenarios would need to clear and ranked the scenarios based on Navigant's understanding of the difficulty of each scenario doing so. The three criteria used for assigning this ranking are:

Does the scenario require a change to legislation (i.e., the Ontario Energy Board Act);

Does the scenario require a change to regulation (i.e., O.Reg 95/05 of the OEB Act); and

Does the scenario require a change to the RPP rules (i.e., the Regulated Price Plan Manual)?

These three criteria for changes are shown in order of difficulty: to change legislation requires a vote in the Ontario provincial parliament, to change regulation requires an Order in Council by the Minister of Energy and changes to the RPP Manual may be enacted by the OEB.

The principal clause of the Ontario Energy Board Act that concerns the setting of rates is (3.3) of 78. in Part V[41]: "the Board shall forecast the cost of electricity to be consumed by consumers to whom the rates apply… and shall ensure that the rates reflect these costs… [and] the Board shall take into account balances in the OPA's variance accounts… and shall make adjustments with a view to eliminating those balances within 12 months…"

That is, the Ontario Energy Board is required to set RPP rates that are cost reflective, that recover system costs on an annual basis and ensure that any variances between revenues and costs are settled within 12 months of their being incurred.

None of the proposed scenarios would require this piece of legislation to be changed. As has been demonstrated in 5.4, below, the rates of all proposed scenarios are reasonably price reflective by season, and the prices in each scenario are set to recover forecast costs.[42]

As concerning regulatory changes, the section of O.Reg 95/05 that is most relevant to the current analysis is that concerned with setting rates, section s. 79.16[43]. This section requires that the Off-Peak period be between 7am and 7pm on non-holiday weekdays and all day on weekends.

The CPP Scenario and the Super-Peak Scenario would require no change to this regulation – neither one of these scenarios proposes any rate other than Off-Peak between 7am and 7pm (EPT) on non-holiday weekdays. It is ambiguous whether the Flat Scenario would require a change to this regulation – in the shoulder season months, the Shoulder period price is in effect 24 hours a day, seven days a week. Given that the absolute level of the Shoulder rate is relatively low, it might be possible to implement this scenario without a change of regulation – for example if, instead of calling it a "Shoulder price", it were called the "shoulder season Off-Peak price".

The CPD Scenario, with a critical peak period that extends until 10pm on event days would likely require a change in regulation, unless the argument could be made that since participation is voluntary, and the critical peak period is just an "overlay" (i.e., a rate rider) the 7am to 7pm period remains "Off-Peak"

Since all of the scenarios proposed differ from the Status Quo TOU structure, the RPP Manual would necessarily need to be amended for all scenarios to reflect the new structure. That said, Navigant believes that all of the proposed scenarios are in line with the objectives for time-of-use pricing laid out in the Manual. These objectives are:

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41 Ontario Energy Board Act, 1998, S.O. 1998, Chapter 15, Schedule B
http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm#s78s3p3

42 Naturally none of them perfectly recovers annual RPP system costs, and the degree to which they fail to do so is quantified by the "Price Stability" metric.

43 Ontario Energy Board Act, 1998, Ontario Regulation 95/05, *Classes of Customers and Determination of Rates*
http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_050095_e.htm

Set prices to recover the full cost of RPP supply; that is, the price structure must, on a forecast basis, recover all of the RPP supply costs from the consumers who pay the prices;

Set the price structure to reflect RPP supply costs; that is, the prices should reflect the differences in cost of supply at different times of the day and year;

Set both prices and the price structure to give consumers incentives and opportunities to reduce their electricity bills by shifting their time of electricity use; and

Create a price structure that is easily understood by consumers.

Given the discussion above, Navigant believes that the CPP Scenario would be the simplest to implement from a legal and regulatory standpoint, whereas the CPD Scenario would be the most time-consuming and complex. Ranking of scenarios for this aspect of implementation is shown in, below.

Figure 57: Scenario Rank for Legal/Regulatory

Implementation Aspect	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Legal/ Regulatory	1	3	2	4	1

Source: Navigant analysis

5.4 Alignment with System Costs

This section of this chapter provides the ranking of the five scenarios by the degree to which the prices in each scenario reflect system marginal costs, as represented by the HOEP. Figure 58 provides the ranking of each scenario (calculated as described in 4.2.2, above). Each scenario receives a rank for each test year and a rank for both years together (the "Overall Rank"). A rank of "1" indicates that the given scenario is the most closely aligned with system marginal costs and a rank of "4" indicates that the given scenario is the least closely aligned with system marginal costs.

Note that the system costs do *not* take into account the impact that any behaviour changes may have on HOEP. As detailed above, the HOEP used is that forecast as part of the May 2013 RPP price-setting fitted to the HOEP profile of the given test year.

Figure 58: Ranking of Scenarios by Alignment with System Costs

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	3	2	4	1	5
2012	3	2	4	1	5
Overall Rank	**3**	**2**	**4**	**1**	**5**

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Detailed plots of normalized average system costs and normalized average scenario prices in each hour of a weekday are provided in Appendix A. Four plots are provided for each scenario:

Two plots (one for RPP winter and one for RPP summer) comparing each scenario's average non-holiday weekday prices (across both test years) with the average system costs in the same period.

Two plots (one for each test year) comparing each scenario's average prices and average system costs to one another on the peak summer demand day of each test year.

Note that for the CPP Scenario and the CPD Scenario, the summer plot described in 0, above *includes* prices in critical peak periods since they are averages across all days in each season.

The plots make it clear that the CPD Scenario has prices that are the most closely aligned with system costs on system peak days. While less obvious (since the differences between the scenarios are smaller) careful comparison of the average day price/cost alignment plots also show that the CPD Scenario average prices are also most closely aligned with average non-holiday weekday system costs.

5.5 Price Stability

This section ranks the price stability of each of the proposed scenarios. As noted above, Navigant has defined price stability as the degree to which forecast RPP revenues, relative to the Status Quo, over- or under-collect on total forecast RPP supply costs. Note that, as above, RPP supply costs do not reflect any change in behaviour as a result of a given scenario..

The annual under- or over-collection of system costs, relative to the Status Quo, in millions of dollars are shown in Figure 59, below, along with the relative rank of each scenario. A positive number indicates an over-collection relative to the Status Quo.

Two things are important to bear in mind when evaluating this result: firstly, as a percent of total RPP revenue (approximately $4.5 billion/year) these variances are trivial. Secondly, these variances are due entirely to the fact that prices are set not anticipating behaviour changes. An iterative price-setting procedure that accounted for behaviour changes could considerably reduce these (already relatively small) variances.

Figure 59: Under- Or Over-Collection of Annual System Costs (Millions $)

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	$0.4	$118.8	$46.9	$0.5	$105.5
2012	$0.6	$149.9	$96.4	$0.5	$133.6
Average	**$0.5**	**$134.4**	**$71.7**	**$0.5**	**$119.6**
Rank:	**2**	**5**	**3**	**1**	**4**

Source: IESO, OEB-provided hourly consumption data and Navigant analysis

All of the proposed scenarios over-collect revenues relative to Status Quo. Naturally the two scenarios (Scenarios 1 – CPP – and 4 - CPD) that affect only 5% of the residential and 2.5% of the GS customer population have the smallest variances from the Status Quo in absolute terms since in both those scenarios the vast majority of customers remain subject to the Status Quo TOU rates.

Two things are important to bear in mind when evaluating this metric: firstly, as a percent of total RPP revenue (approximately $4.5 billion/year) these variances are trivial. Secondly, these variances are due entirely to the fact that prices are set not anticipating behaviour changes. An iterative price-setting procedure that accounted for behaviour changes could considerably reduce these (already relatively small) variances.

5.6 Summary of Metrics

This section summarizes the ranks applied to each proposed scenario and calculates the overall most highly ranked scenario. The ranks achieved by each scenario are summarized in Figure 60, below. Recall that the lower the rank, the more desirable the scenario – for a given metric a rank of 1 indicates the "best" scenario, and a rank of 5, the "worst".

Figure 60: Summary of Ranking by Metric and Scenario

Metric	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
Peak System Demand Impact	3	4	5	2	1
Alignment With System Costs	3	2	4	1	5
Ease of Implementation	2	3	4	4	1
Price Stability	2	5	3	1	4
Overall Average (Unweighted) Rank	**2**	**4**	**5**	**1**	**3**

Source: Navigant analysis

The highest ranked scenario overall is the CPD Scenario, the Status Quo with Critical Peak Day pricing. It delivers the highest estimated system peak demand impacts, is the scenario most closely aligned with system costs and is also the scenario that delivers the most price stability, relative to the Status Quo. Unfortunately it is also the scenario that Navigant believes to be the most difficult to implement in practice.

the CPP Scenario is the second best option proposed. Despite its relative misalignment with system marginal costs, it is the only scenario other than the CPD Scenario that delivers system peak demand reductions.

6 Informational Outputs

This chapter provides a summary of informational outputs of the analysis – factors of interest to policy-makers but not metrics weighed to determine the desirability of any given scenario. This chapter is divided into two sections:

- **Unit Cost Impacts by Customer Type.** The estimated impact of each scenario on customer unit electricity costs for an average customer, a customer with relatively high levels of Off-Peak period consumption and a customer with relatively low levels of Off-Peak period consumption.

- **Changes in Energy Consumption.** The estimated aggregate change in energy consumption as a result of each scenario.

6.1 Unit Cost Impacts by Customer Type

This section provides the estimated change in the average unit cost ($/kWh) per customer for the two rate classes and the three customer types. The unit cost of electricity is the sum of all variable electricity costs per kWh of consumption – i.e., the sum of commodity and non-commodity (distribution charges, etc.) costs.

The three "types" of customers for whom Navigant has estimated unit cost impacts are:

- **Average customers:** customers with the average load profile for their rate class;

- **Type 1 customers:** customers with relatively high levels of Status Quo Off-Peak consumption; and

- **Type 2 customers:** customers with relatively low levels of Status Quo Off-Peak consumption.

This section is divided into three sub-sections, each one corresponding to each of the customer types noted above.

6.1.1 Average Customers

This sub-section provides and discusses the estimated unit cost impact of each scenario on an "average" residential and GS customer.

Residential Customers

Figure **61** shows the average unit cost impact of each scenario on an "average" residential customer. Two sets of cost impacts are shown: the cost impact if the customer does not respond to the scenario prices (i.e., no change to the load profile from Status Quo) and the cost impact if the customer responds to the scenario prices as suggested by the estimated elasticities. A positive number indicates an increase in what the customer pays, a negative number indicates a decrease to that customer's unit electricity cost. For reference, the average annual variable cost of electricity for a residential customer is approximately $1,200. The percentages in Figure **61**, below, may be applied to this number to obtain an estimate of the annual variable cost impact to an average customer. For example, using the 2012 test year data, an average customer *that does not change behaviour at all* to respond to the CPD rates will observe an annual increase in variable costs of approximately $12.

Figure 61: Average Residential Customer Unit Cost Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	1%	2%	3%	0%	1%
2012	1%	3%	3%	1%	2%
Average	**1%**	**2%**	**3%**	**0%**	**2%**
Price Response as Modeled by Elasticities					
2011	0%	2%	0%	0%	0%
2012	0%	2%	1%	0%	1%
Average	**0%**	**2%**	**1%**	**0%**	**0%**

Source: OEB-provided hourly consumption data and Navigant analysis

All five scenarios, with no change in behaviour, result in the average residential customer paying more for his electricity than in the Status Quo. Once changes in behaviour are taken into account, an average residential customer participating in Scenarios 1 (CPP), 4 (CPD) or 5 (ESQ) is estimated to have a unit cost no different than under the Status Quo.

GS Customers

The unit cost impacts (shown in Figure 62) on an average GS customer are very similar to those experienced by an average residential customer for most of the scenarios. GS customers do not realize as much of a cost reduction for the CPP Scenario as for the CPD Scenario (where costs do not change) This is due principally to the hours in which discounted electricity prices (as an incentive to participate in the critical peak rate) are offered. The most significant contrast between the residential and GS results is for the ESQ Scenario. Whereas residential customers, after behaviour changes, experienced no average change in unit cost, GS customers experience an average increase in unit costs of 5%.

For reference, the average annual variable cost of electricity for a GS customer is approximately $2,500.

Figure 62: Average GS Customer Unit Cost Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	1%	2%	2%	0%	5%
2012	1%	3%	2%	0%	5%
Average	**1%**	**3%**	**2%**	**0%**	**5%**
Price Response as Modeled by Elasticities					
2011	0%	2%	1%	-1%	5%
2012	1%	3%	2%	0%	5%
Average	**1%**	**2%**	**1%**	**0%**	**5%**

Source: OEB-provided hourly consumption data and Navigant analysis

the ESQ Scenario results in such a dramatic unit cost impact (relative to residential customers) due principally to the underlying GS load shape. GS customers tend to consume the majority of their energy in the 7am to 7pm window on weekdays (i.e., standard business hours). In the ESQ Scenario it is precisely these hours in which prices increase considerably. The basic underlying GS load shape and (estimated) relative inelasticity of GS demand mean that there is little scope for GS customers to take advantage of the Off-Peak discount offered by the ESQ Scenario.

For the CPP Scenario, participating customers pay a discounted price for Off-Peak consumption, whereas for the CPD Scenario, participating customers pay a discounted price for Mid-Peak and On-Peak consumption on non-critical peak days. The majority of GS customers' consumption occurs during the Mid-Peak and On-Peak periods, so the CPP Scenario discounted Off-Peak price does not deliver sufficient cost savings to offset the increased critical peak costs, whereas the discounted Mid-Peak and On-Peak prices in the CPD Scenario do.

6.1.2 Type 1 Customers (Off-Peak Consumption High in Proportion to Total Consumption)

This sub-section provides and discusses the estimated unit cost impact of each scenario on Type 1 (as defined above) residential and GS customer.

Note that the unit cost impacts with behaviour changes for type 1 customers implicitly assume that the elasticities estimated for average customers (in Part 1 of this study) apply to a type 1 customer.

This may be a flawed assumption – the very fact that these customers consume a higher proportion of their electricity in the Off-Peak period than the average customer suggests that these customers may have a different level of price responsiveness than average customers across all periods.

Residential Customers

Figure 63 shows the unit cost impacts estimated for a Type 1 residential customer under each scenario. The most significant difference between the Type 1 residential customer cost impacts and the average residential customer unit cost impacts is for the CPP Scenario. Type 1 customers achieve (after behaviour response) savings in the CPP Scenario where an average customer would observe no change to unit costs. For reference, the average annual variable cost of electricity for a Type 1 residential customer is approximately $900.

Figure 63: Type 1 Residential Customer Unit Cost Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	0%	2%	2%	1%	-3%
2012	0%	2%	2%	1%	-3%
Average	**0%**	**2%**	**2%**	**1%**	**-3%**
Price Response as Modeled by Elasticities					
2011	-1%	2%	0%	1%	-4%
2012	-1%	2%	1%	0%	-4%
Average	**-1%**	**2%**	**1%**	**0%**	**-4%**

Source: OEB-provided hourly consumption data and Navigant analysis

This change in unit costs from the average customer to a Type 1 customer is simply due to how the Type 1 customer is defined and the discounts offered in each scenario. Recall that a Type 1 customer is one with a relatively high level of Off-Peak consumption and that in the CPP Scenario the incentive for participation in the critical peak program is a discounted Off-Peak price. As would be expected, residential unit costs fall the most for the ESQ Scenario where Off-Peak prices are discounted for the entire year, greatly benefiting Type 1 customers since a high proportion of their consumption is already in this period.

GS Customers

Figure 64 shows the unit cost impacts estimated for Type 1 GS customers. For the CPP Scenario and the Super-Peak Scenario the GS Type 1 customers achieve modest reductions in unit cost. For the ESQ Scenario GS Type 1 customers achieve significant reductions in unit cost. For reference, the average annual variable cost of electricity for a Type 1 GS customer is approximately $850.

Figure 64: Type 1 GS Customer Unit Cost Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	-2%	3%	0%	0%	-6%
2012	-4%	3%	-1%	0%	-14%
Average	**-3%**	**3%**	**-1%**	**0%**	**-10%**
Price Response as Modeled by Elasticities					
2011	-2%	3%	0%	0%	-7%
2012	-4%	3%	-1%	0%	-16%
Average	**-3%**	**3%**	**-1%**	**0%**	**-12%**

Source: OEB-provided hourly consumption data and Navigant analysis

As with residential Type 1 customers, these results are due to the load shape of the customers in question. Type 1 GS customers, after behaviour changes in test year 2012 consume virtually no electricity during the summer Super-Peak (1pm to 7pm) and On-peak periods (11am to 5pm) – just 0.2% and 0.3% of their 2012 consumption is from these periods, respectively. By contrast, an *average* GS customer (results for which are shown in Figure 62, above) in test year 2012, even after behaviour changes, consumes about 5% of his annual electricity consumption in the On-Peak period and another 5% in the Super-Peak period. It is therefore no surprise that scenarios that offer the steepest discount on Off-Peak consumption result in the largest reductions in GS customer unit cost.

6.1.3 Type 2 Customers (Off-Peak Consumption High in Proportion to Total Consumption)

This sub-section provides and discusses the estimated unit cost impact of each scenario on Type 2 (as defined above) residential and GS customers. As noted above, behaviour impacts for Type 2 customers are estimated based on the average elasticities estimated in Part 1 and thus will likely be less accurate in predicting Type 2 customer behaviour response than in predicting an average customer's behaviour response.

Residential Customers

Figure 65 shows the unit cost impacts estimated for Type 2 residential customers. For reference, the average annual variable cost of electricity for a Type 2 residential customer is approximately $1,100.

Figure 65: Type 2 Residential Customer Unit Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	2%	2%	2%	0%	6%
2012	2%	3%	3%	0%	7%
Average	**2%**	**3%**	**3%**	**0%**	**6%**
Price Response as Modeled by Elasticities					
2011	0%	2%	0%	0%	4%
2012	1%	2%	1%	0%	5%
Average	**0%**	**2%**	**0%**	**0%**	**5%**

Source: OEB-provided hourly consumption data and Navigant analysis

The impacts for Type 2 customers are as expected for each of the scenarios. In the CPP Scenario, for example, since Type 2 customers use relatively less Off-Peak consumption, they cannot realize the benefit of the discounted Off-Peak price in this scenario in the same way that average residential customers can (note the 1% increase for the CPP Scenario for test year 2012 after price response, compared to 0% in the same cell for *average* residential customers). Likewise, Type 2 residential customers will realize significant unit cost increases under the ESQ Scenario since this scenario considerably increases the price of all weekday electricity consumption between 7am and 7pm, electricity that makes up a disproportionate amount of Type 2 customers' consumption, compared with average customers.

GS Customers

Figure **66** shows the unit cost impacts estimated for Type 2 GS customers. As was the case with Type 2 residential customers, and for the same reasons, Type 2 GS customers pay relatively more in the CPP Scenario than average GS customers and less in the CPD Scenario. Type 2 GS customers pay significantly more per unit in the ESQ Scenario than do average customers simply because, as for Type 2 residential customers, most of their consumption happens during the (under the ESQ Scenario) most highly priced periods. For reference, the average annual variable cost of electricity for a Type 2 GS customer is approximately $2,400.

Figure 66: Type 2 GS Customer Unit Cost Impacts

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
No Price Response					
2011	3%	3%	2%	-1%	17%
2012	3%	3%	3%	-1%	17%
Average	**3%**	**3%**	**3%**	**-1%**	**17%**
Price Response as Modeled by Elasticities					
2011	3%	3%	1%	-1%	14%
2012	3%	3%	2%	-1%	14%
Average	**3%**	**3%**	**2%**	**-1%**	**14%**

Source: OEB-provided hourly consumption data and Navigant analysis

6.2 Changes in Energy Consumption

Figure 67 shows the impact of each scenario on residential energy consumption (GWh/year) in each of the two test years. A negative number in this table indicates a reduction in energy consumption and a positive number indicates an increase.

As expected, due to assumed participation (5% of residential customers), the CPP Scenario and the CPD Scenario had a minimal impact on energy consumption in either test year. The increase in consumption in both scenarios is due to the discounts offered to customers in non-critical peak periods.

The Flat Scenario resulted in a mild conservation impact in both years. This is likely due to the fact that residential customers are less price-sensitive in the Shoulder seasons than the winter and summer, and it was in the shoulder season where prices were considerably reduced (relative to the Status Quo).

Scenarios 3 (Super-Peak) and 5 (ESQ) resulted in a moderate increase in energy consumption due to the discount those scenarios offers customers on all non-holiday weekdays. Increased consumption due to this discount more than compensates for the reduction in consumption during the summer Super Peak periods (for the Super-Peak Scenario) or all the Mid-Peak and On-Peak periods (for the ESQ Scenario).

Although the approximately 300 GWh increase in energy consumption for Scenarios 3 (Super-Peak) and the ESQ Scenario may appear to be fairly significant, it is less than 1% of the approximately 40,000 GWh estimated to have been consumed by residential customers annually. Likewise, none of the energy impacts from the other scenarios exceeds half a percent change in total annual residential energy consumption.

Figure 67: Residential Energy Impact (GWh/Year) by Scenario

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	9.7	-48.1	346.0	1.2	268.9
2012	9.6	-37.3	261.0	2.2	247.6
Average	**9.7**	**-42.7**	**303.5**	**1.7**	**258.2**

Source: OEB-provided hourly consumption data and Navigant analysis

Figure 68 shows the impact of each scenario on GS energy consumption (GWh/year) in each of the two test years. The GS impacts are directionally the same as for residential customers (and are driven by the same factors) in all the scenarios except for the Super-Peak Scenario.

The Super-Peak Scenario results in a conservation impact for GS customers due to the lack of cross-price effects – on summer weekdays there is no “pre-cooling” or “snapback” estimated for GS customers in response to the Super-Peak period. Amongst residential customers, these cross-price effects counteract energy savings that are achieved during the Super Peak period – for GS customers this is not the case. For none of the scenarios do GS energy impacts exceed a 0.1% change in total annual GS energy consumption.

Figure 68: GS Energy Impact (GWh/Year) by Scenario

Test Year	CPP Scenario	Flat Scenario	Super-Peak Scenario	CPD Scenario	ESQ Scenario
2011	0.2	-9.7	-15.9	0.1	9.2
2012	0.1	-11.2	-18.0	0.0	7.2
Average	**0.1**	**-10.4**	**-16.9**	**0.0**	**8.2**

Source: OEB-provided hourly consumption data and Navigant analysis

7 Observations and Considerations

This final chapter of the report is split into two sections.

Observations: This section presents the most important of Navigant's observations from its analysis of the five proposed alternative TOU scenarios.

Considerations: This section presents Navigant's considerations regarding next steps.

7.1 Conclusions

Of the five scenarios evaluated by Navigant for this study, the CPD Scenario ranked as the "best" according the metrics applied, and the Super-Peak Scenario ranked the worst. The CPD Scenario's rankings by metric were remarkably consistent – for two out of the four metrics it scored the "best" and for one of the four it ranked second-best, although, perhaps unsurprisingly, it ranked as the "worst" for ease of implementation.

It must be noted that this overall ranking is based on an unweighted average of rankings in each of the four metrics. Applying weighting to the metrics – for example weighting the peak demand impact of a scenario to be worth more than the price stability metric – would change the overall ranking.

Navigant's principal observation is that policymakers designing electricity rates should be wary of unintended consequences – customers' responses to rates are complex.

More specifically Navigant's main conclusions from this evaluation are:

Presently, system peak demand is a plateau, not a summit. Rates that target relatively short periods of the day, aiming to reduce system peak will tend to be ineffective and simply shuffle demand to earlier or later hours that are *also* system peak demand hours. This observation may have implications for peak demand reductions attributed to demand response programs, if those programs generate any snapback.[44] Navigant recognizes, however, that the profile of peak demand is evolving and the proliferation of embedded solar generation is likely to change it.

Top ten system peak demand hours can – and often do – occur in Status Quo Off-Peak hours. With the current system load shape, a non-trivial number of the top ten system hours occur in hours with the lowest TOU price. The only way to use electricity prices to reduce consumption in these Off-Peak system peak hours would be either increase the Off-Peak rate or extend the Mid-Peak period later in the day.

The estimated peak demand impacts are based on the net system load shape <u>as it currently is, not necessarily as it may become</u>. Increased penetration of solar PV could considerably alter the system

[44] "Snapback" refers to an increase in electricity demand immediately following a critical peak pricing or direct load control event that may be attributable to that event.

load shape and thus the net system peak demand impacts of the various scenarios. Appendix C (below) illustrates the degree to which peak demand impacts are sensitive to the shape of system demand.

Simply raising the price of electricity in a period will not necessarily reduce consumption in that period. Consider the case of the Flat Scenario – despite the price increasing in the summer Status Quo On-Peak (11am – 5pm) period, the larger price increase in the summer Mid-Peak period (7am to 11am and 5pm to 7pm) resulted in consumption in the Status Quo On-Peak increasing, not decreasing.

A sharper price differential within the current TOU structure could yield meaningful peak demand reductions. Of all the scenarios, the ESQ Scenario yielded the most significant absolute demand reductions. This was for two reasons: undesired cross-price effects were mitigated by maintaining a differential between On-Peak and Mid-Peak prices (unlike in the Flat Scenario) and overall the price of electricity was raised considerably from 7am to 7pm, a period covering most (but not all) of the current system peak hours.

If prices are extremely high in every weekday afternoon of the summer, customer demand shifting could lead to an even higher peak earlier in the day. In the Super-Peak Scenario, the estimated elasticities imply that customers would implement a significant amount of pre-cooling in the earlier hours of the day, which could actually increase the system peak demand.

Calling critical peak periods on consecutive days is likely to mute the desired effect. As modeled, when critical peak periods are called on consecutive days the effectiveness of the rate in reducing peak demand is compromised – customers may become exhausted with responding and may respond less on average to each event. This observed result is driven partly by the manner in which customer price response is modeled – customers are modeled such that they allocate their consumption (as driven by the estimated elasticities) by week. While Navigant believes that this reasonably reflects reality, the hypothesis of reduced critical event effectiveness when events are clustered should be tested.

The observations above are driven entirely by the estimated elasticities employed by Navigant. Although Navigant is very confident that these deliver robust and accurate results in-sample, it must be remembered that every single one of the scenarios modeled is considerably outside of the sample from which the elasticities were estimated. At no time in the estimation sample after the introduction of TOU rates did the price in one TOU period increase while another one decreased. Likewise, the most expensive commodity prices for each scenario are all outside the range of commodity prices observed in the estimation sample.

7.2 Considerations

Given the results of the evaluation discussed above, and Navigant's observations based on these results, Navigant's two key considerations are (i) that increasing the Status Quo price differentials could yield material peak demand reductions and (ii) that there is value in using a pilot program to confirm the accuracy of the modeled behaviour impacts under the CPP and CPD Scenarios.

Even without the use of administrative pricing (i.e., relying on arbitrary ratios such as the 1:3:4 set used for the ESQ Scenario), there are mechanisms in the RPP Manual that would allow more of the Global Adjustment costs to be recovered in the On-Peak and Mid-Peak periods, thus raising the rate in those periods relative to the Status Quo and the Off-Peak price.

A set of CPP and CPD pilot programs could confirm (or dismiss) the modeled findings of this study. In particular:

- the magnitude of customer response to critical peak prices in the event period;
- the magnitude of demand shifting to periods immediately adjacent to the critical peak period (i.e., do the actual own- and cross-price effects resemble those modeled?); and
- the effect on event impacts if a full week of consecutive events are called (i.e., how substantial is event fatigue? does the clustering of peak demand days really affect impacts as modeled?)

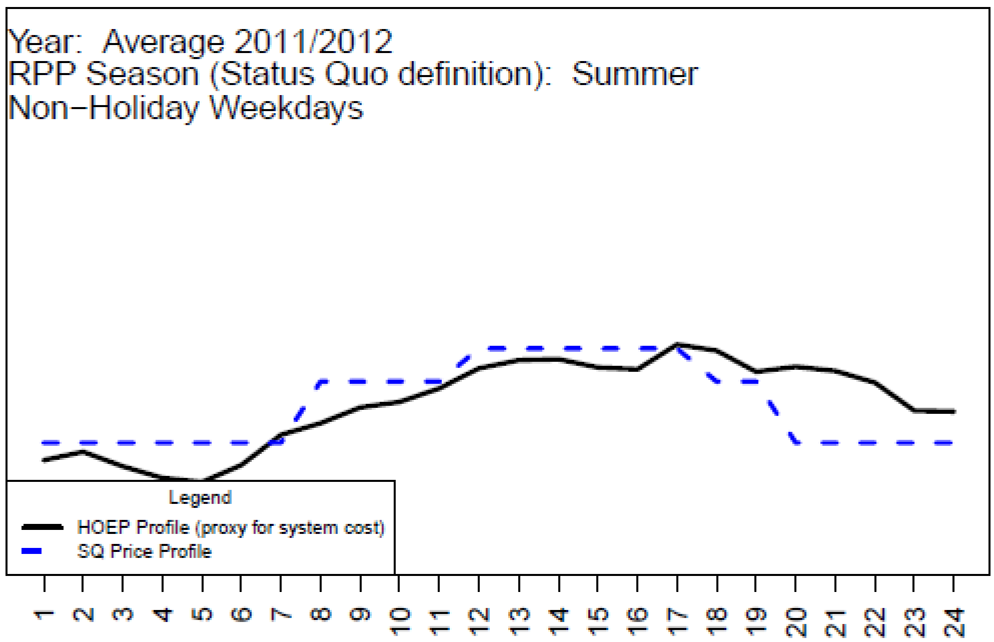
Greater certainty of potential program participation obtained though the use of a carefully designed provincial survey could be combined with estimated relationships from a CPP or CPD pilot to provide a robust projection of the provincial benefits of provincial CPP or CPD program.

Appendix A – Alignment with System Cost Plots

Status Quo

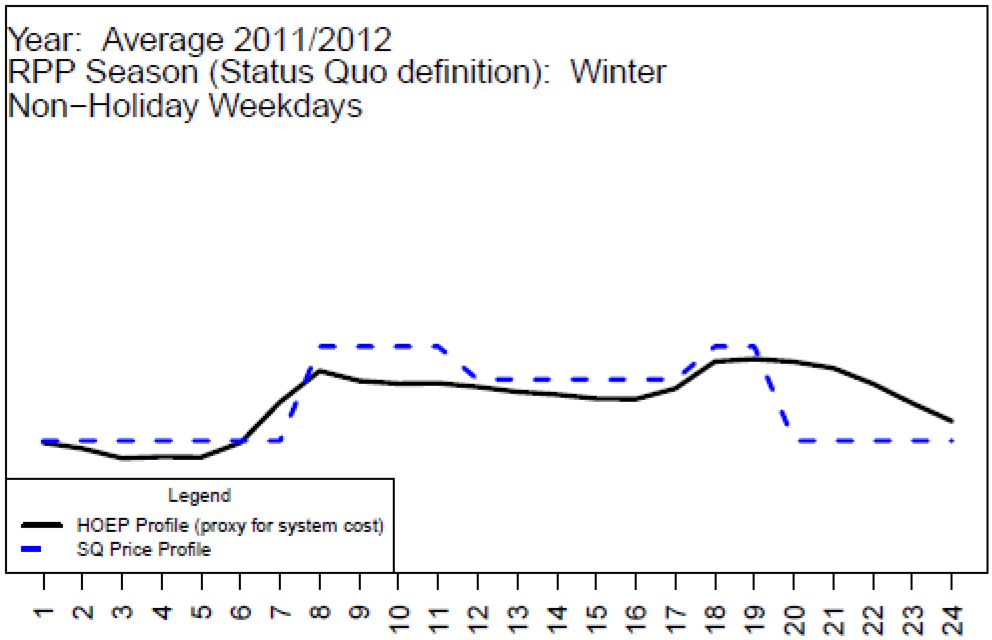
This sub-section provides the four plots described above for the Status Quo.

Figure 69: Status Quo Price/Cost Alignment – Average RPP Summer Weekday



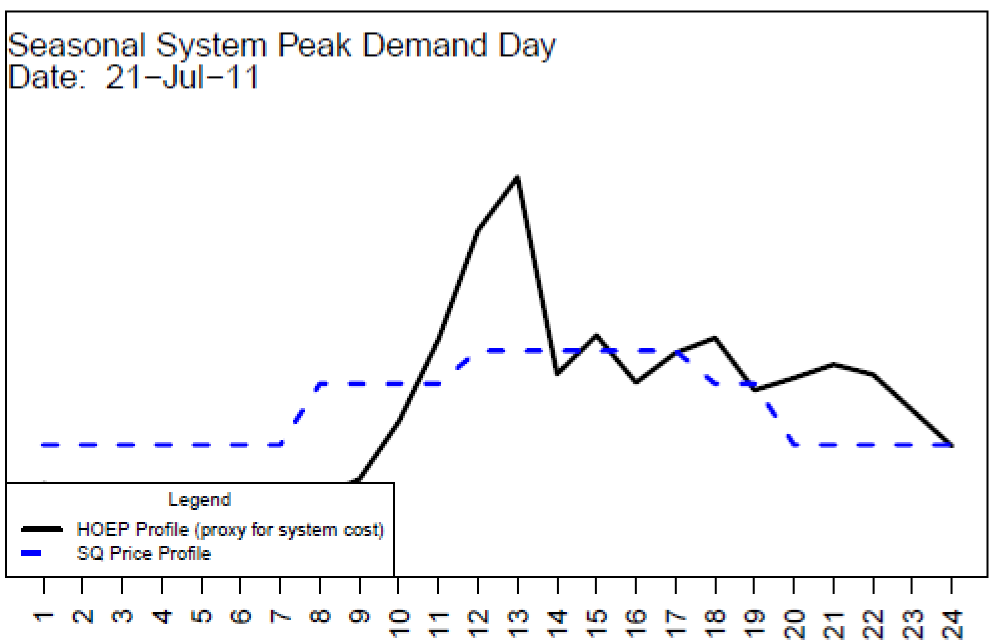
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 70: Status Quo Price/Cost Alignment – Average RPP Winter Weekday



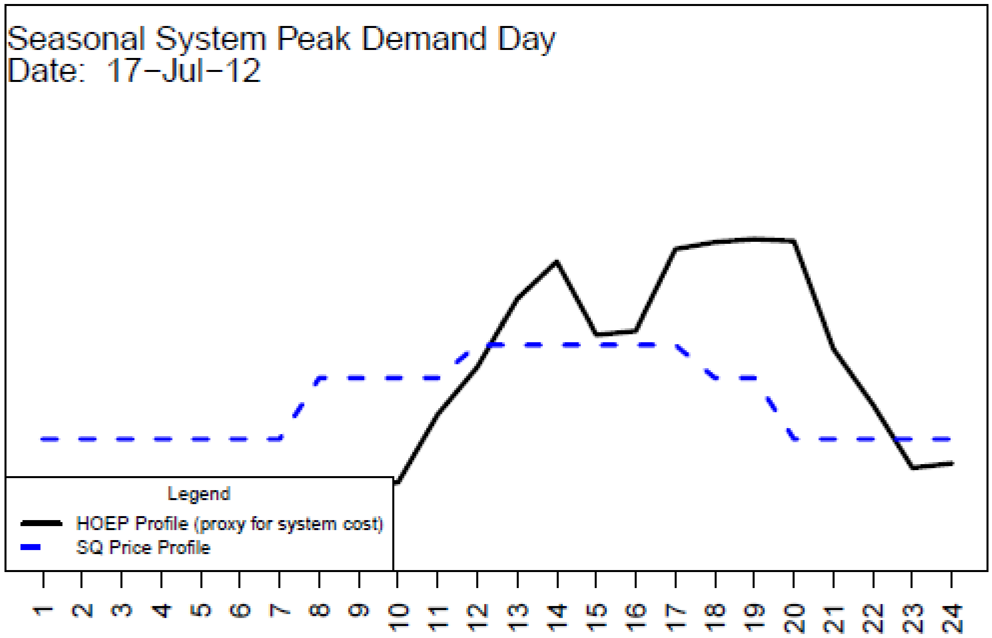
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 71: Status Quo Price/Cost Alignment – Peak Demand Day, Test Year 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 72: Status Quo Price/Cost Alignment – Peak Demand Day, Test Year 2012

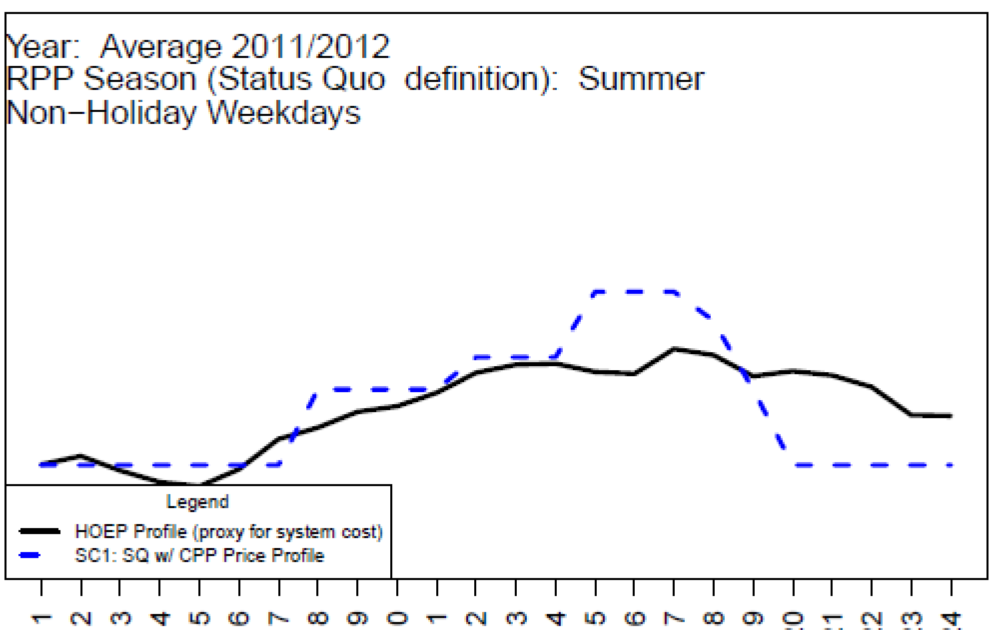


Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Scenario 1: Status Quo with CPP Prices

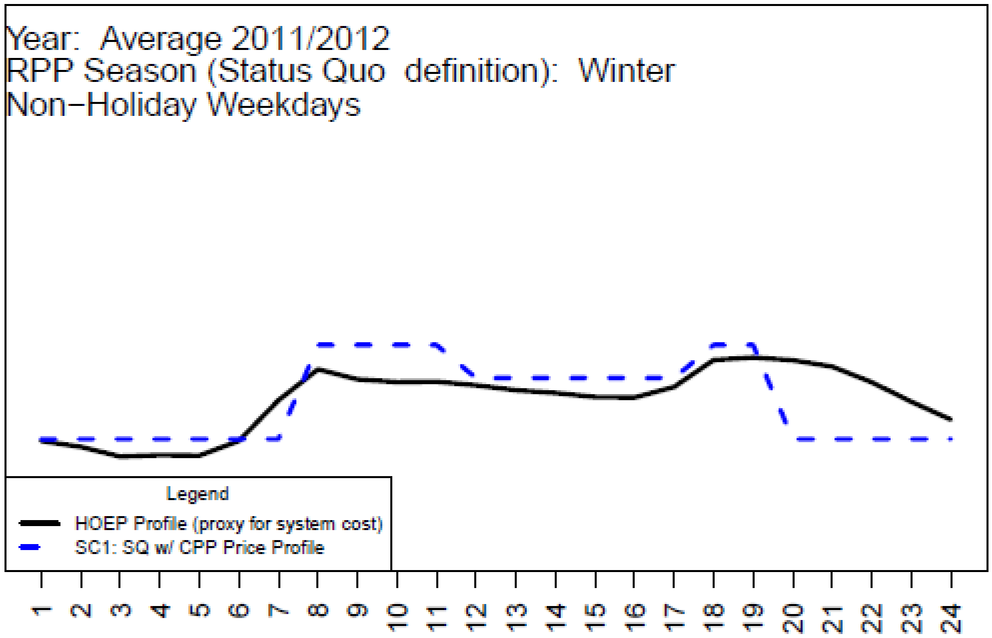
This sub-section provides the four plots described above for the CPP Scenario.

Figure 73: The CPP Scenario Price/Cost Alignment – Average RPP Summer Weekday



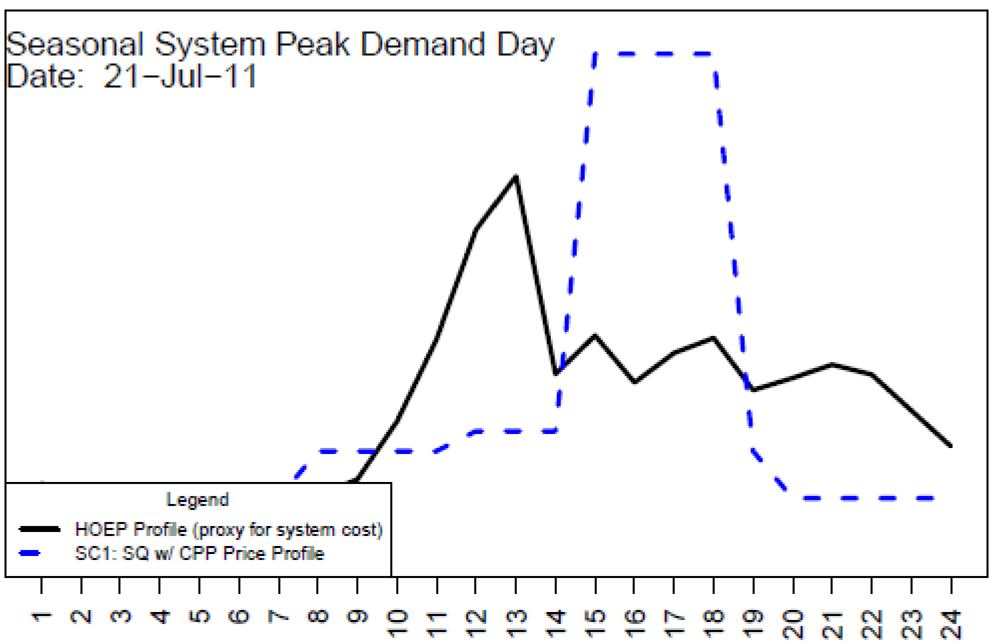
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 74: The CPP Scenario Price/Cost Alignment – Average RPP Winter Weekday



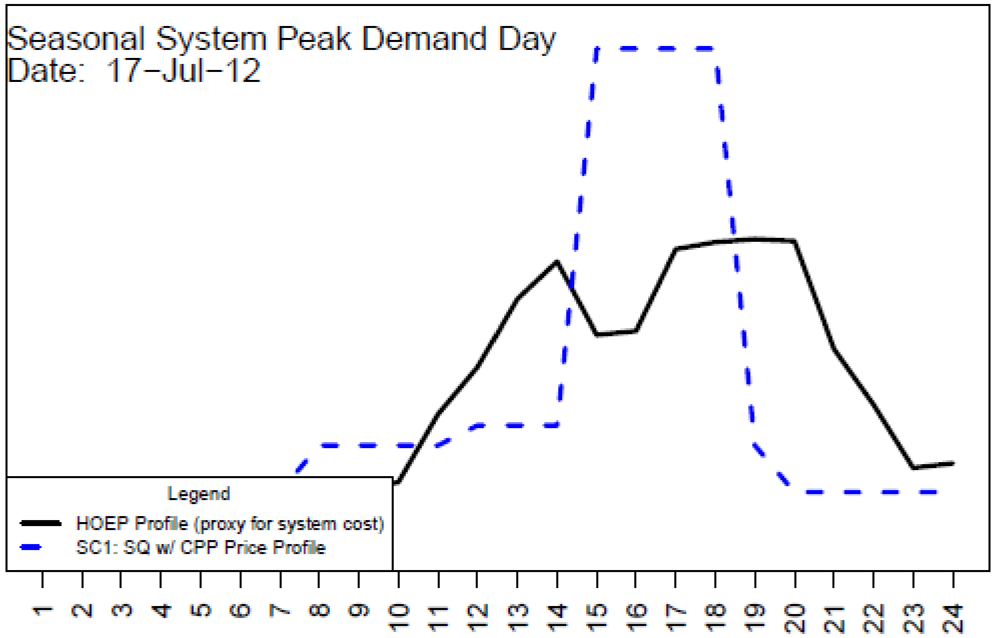
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 75: The CPP Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 76: The CPP Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2012

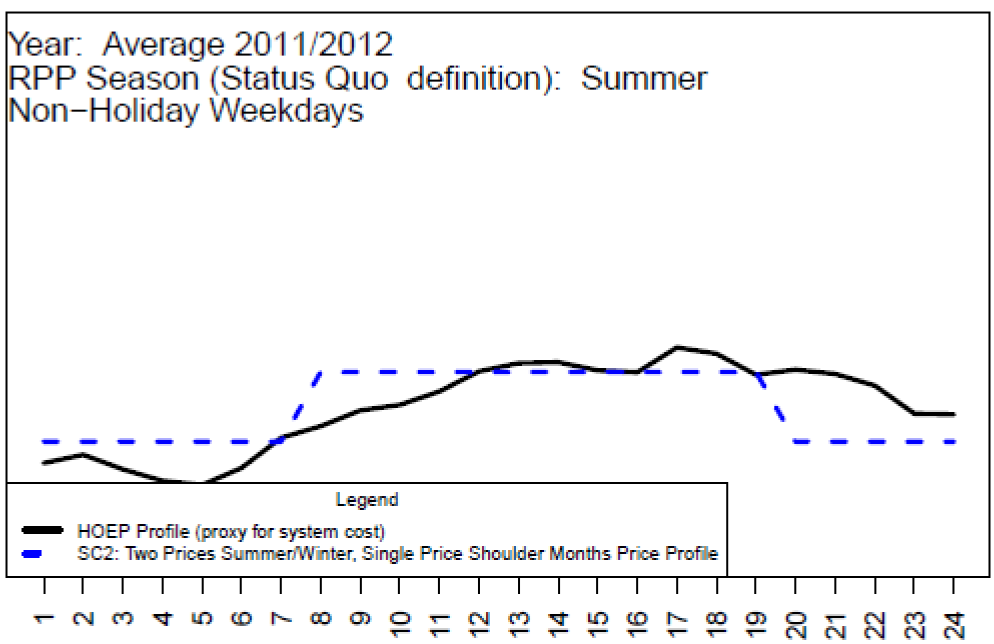


Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Scenario 2: Two Prices Winter/Summer, One Price Shoulder

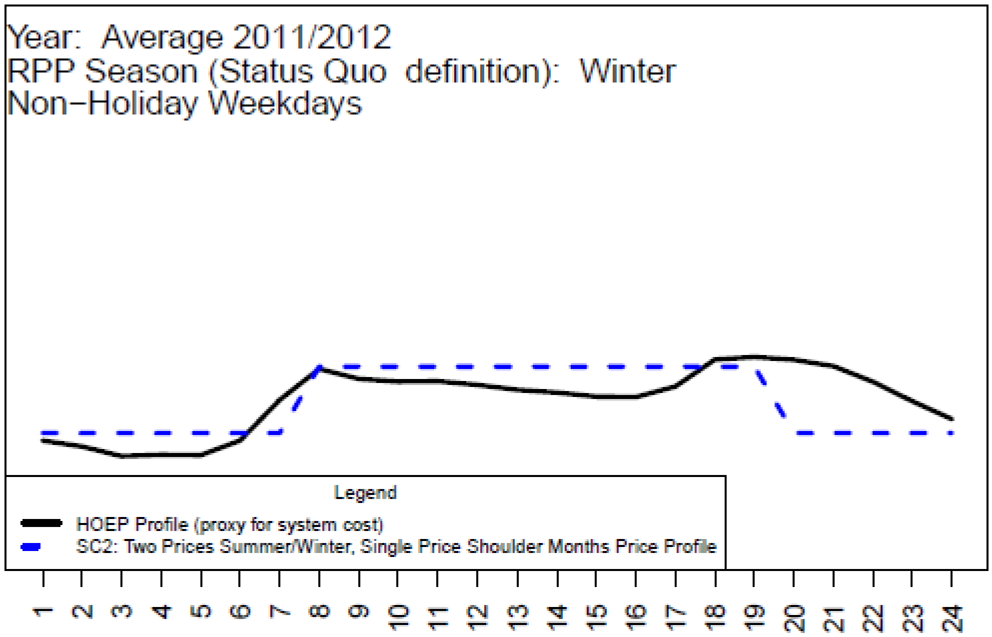
This sub-section provides the four plots described above for the CPP Scenario.

Figure 77: The Flat Scenario Price/Cost Alignment – Average RPP Summer Weekday



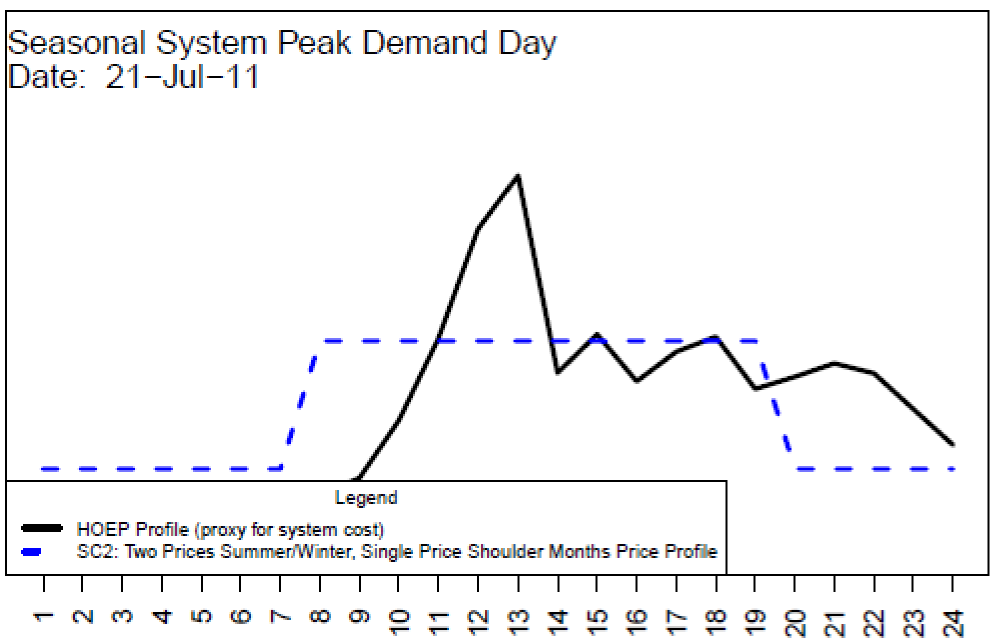
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 78: Scenario 2 Price/Cost Alignment – Average RPP Winter Weekday



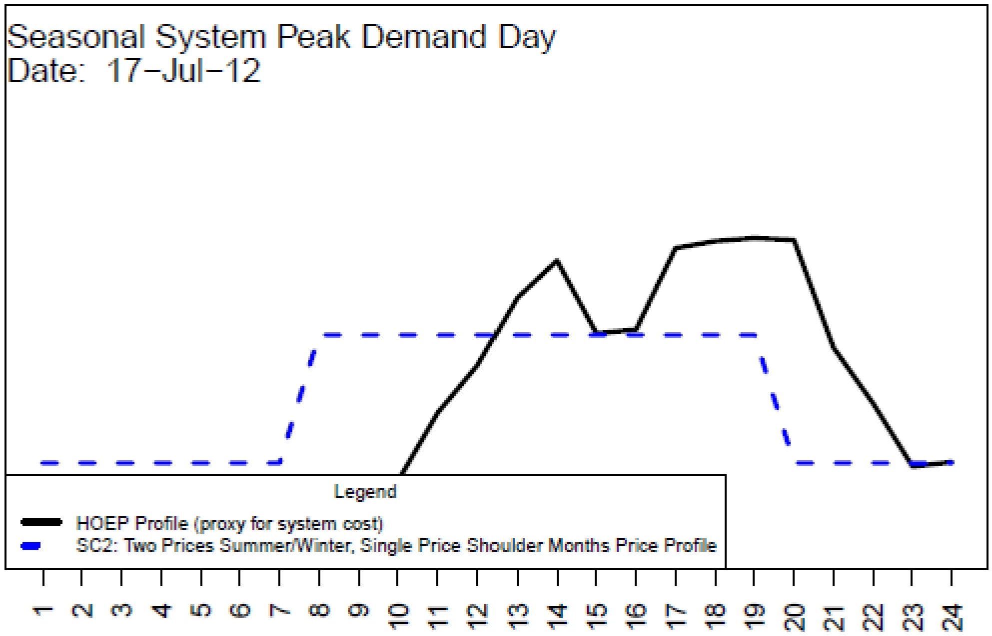
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 79: The Flat Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 80: The Flat Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2012

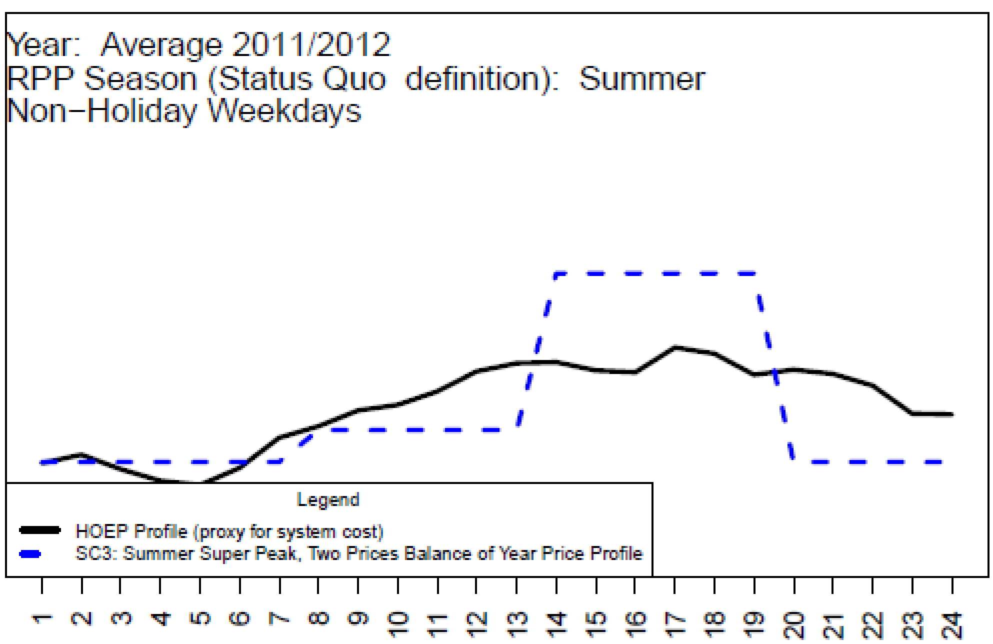


Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Scenario 3: Summer Super Peak

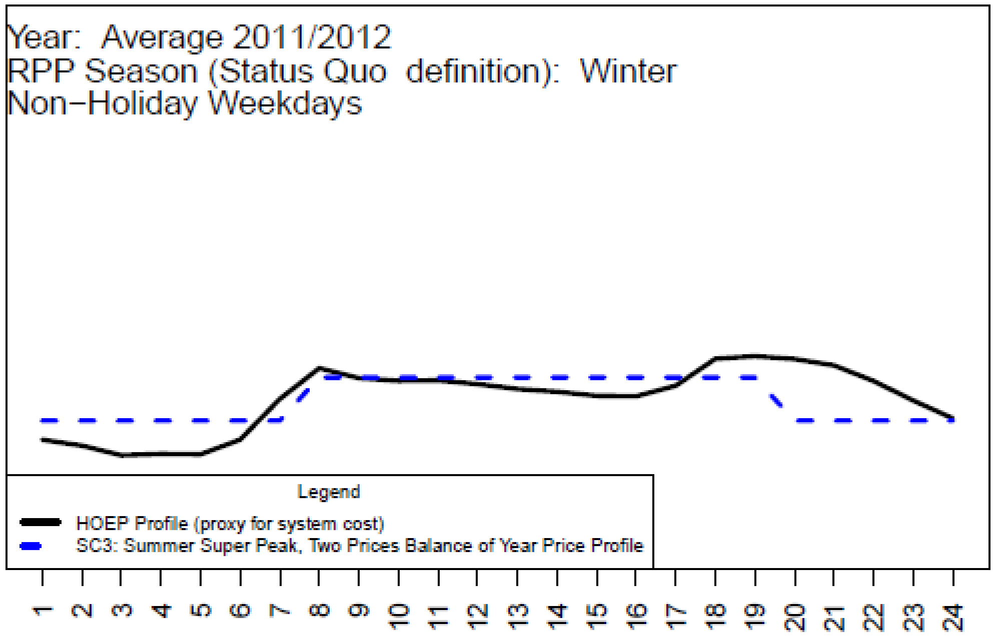
This sub-section provides the four plots described above for the Super-Peak Scenario.

Figure 81: The Super-Peak Scenario Price/Cost Alignment – Average RPP Summer Weekday



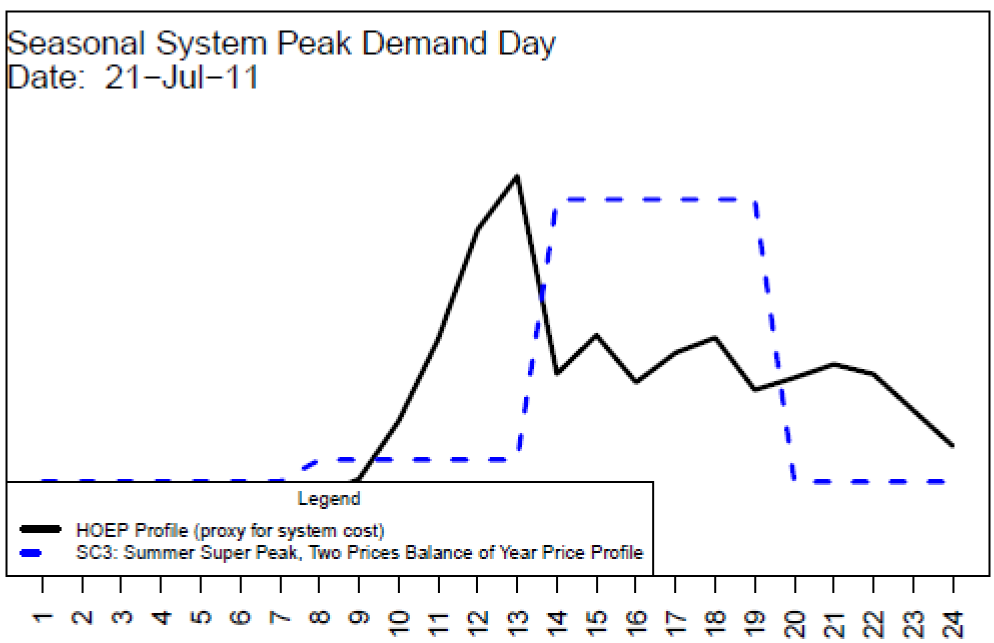
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 82: The Super-Peak Scenario Price/Cost Alignment – Average RPP Winter Weekday



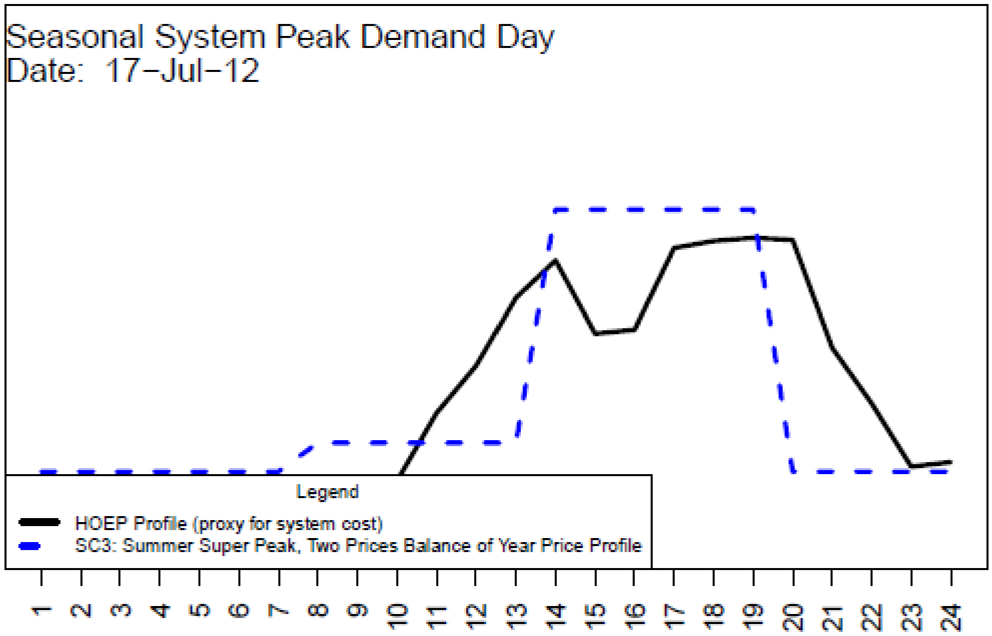
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 83: The Super-Peak Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 84: The Super-Peak Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2012

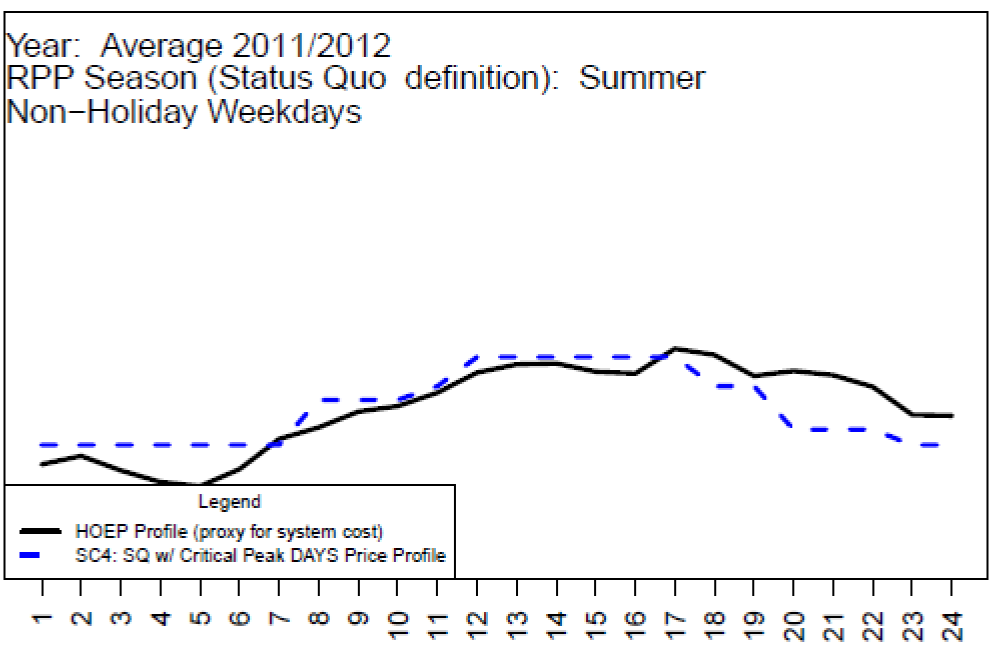


Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Scenario 4: Status Quo with Critical Peak Day Prices

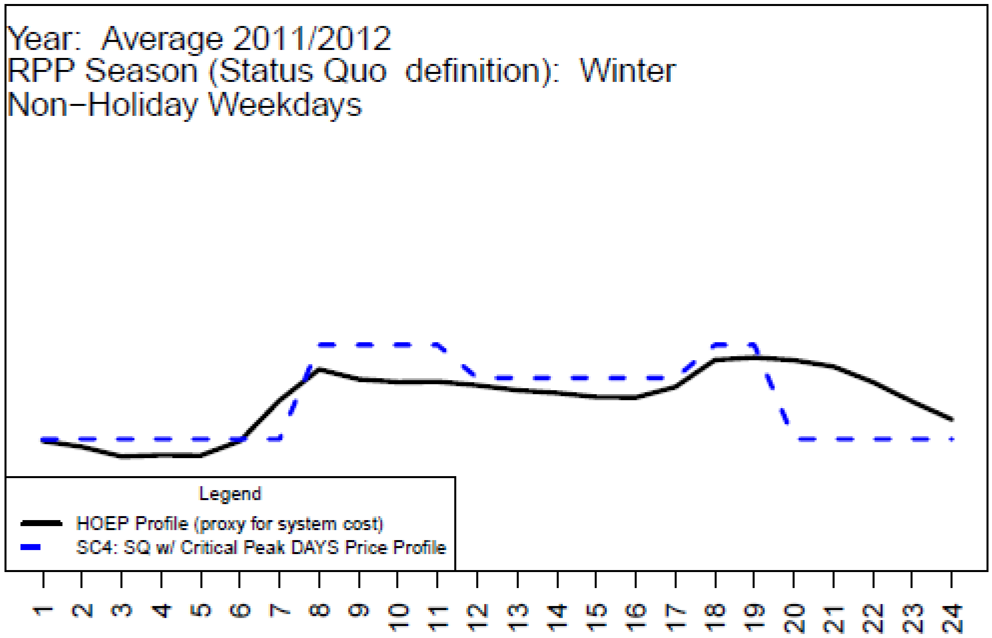
This sub-section provides the four plots described above for the CPD Scenario.

Figure 85: The CPD Scenario Price/Cost Alignment – Average RPP Summer Weekday



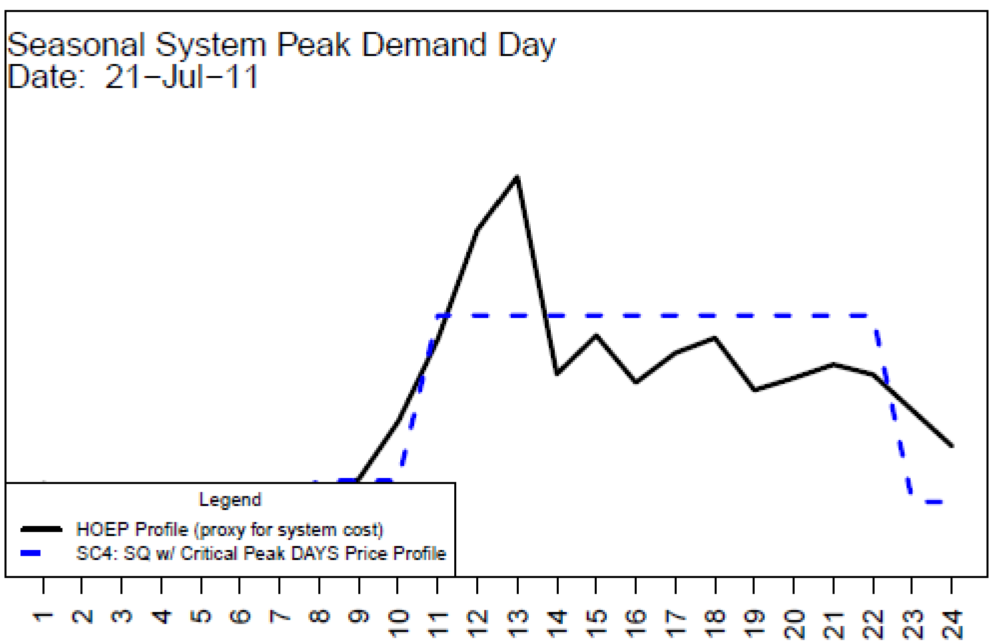
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 86: The CPD Scenario Price/Cost Alignment – Average RPP Winter Weekday



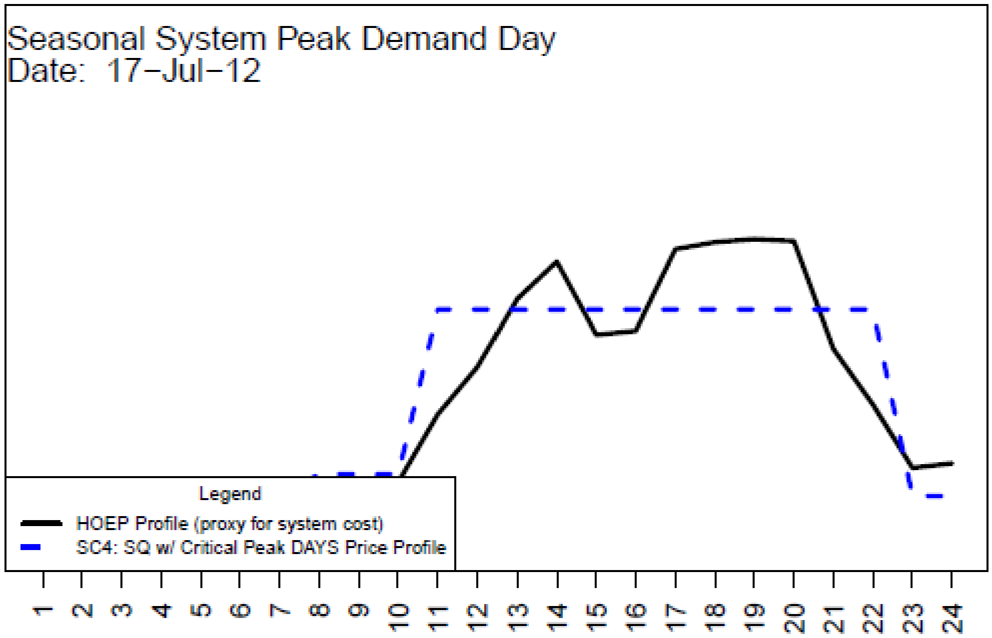
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 87: The CPD Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 88: The CPD Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2012

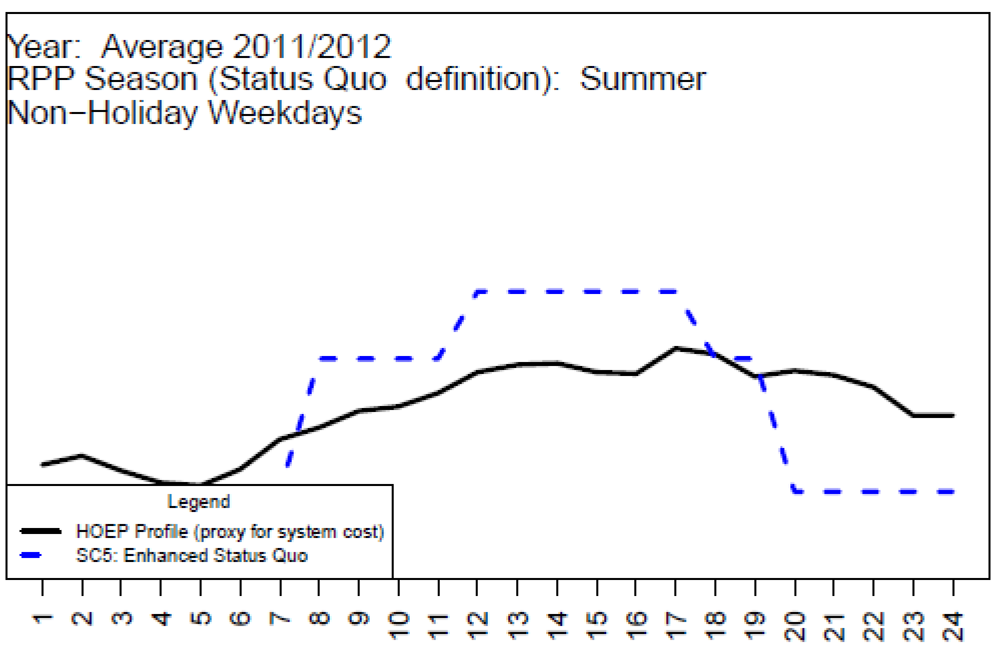


Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Scenario 5: Status Quo with Critical Peak Day Prices

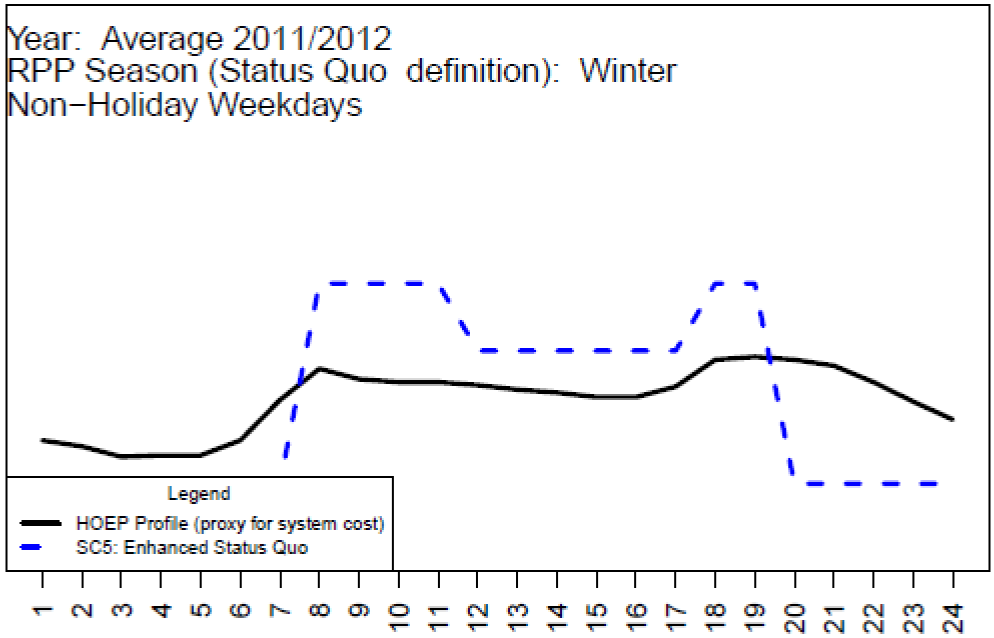
This sub-section provides the four plots described above for the ESQ Scenario.

Figure 89: The ESQ Scenario Price/Cost Alignment – Average RPP Summer Weekday



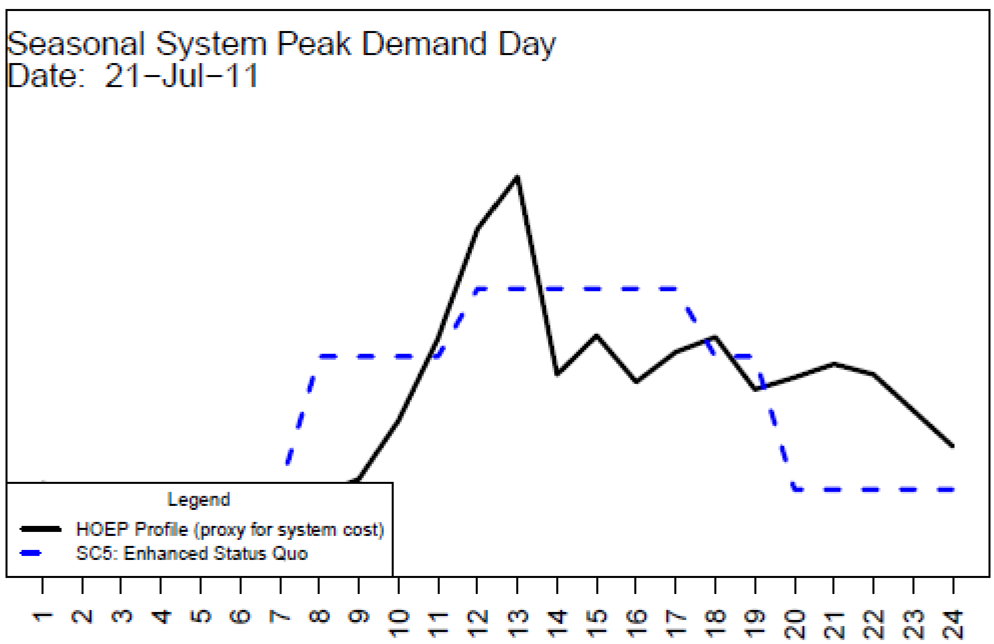
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 90: The ESQ Scenario Price/Cost Alignment – Average RPP Winter Weekday



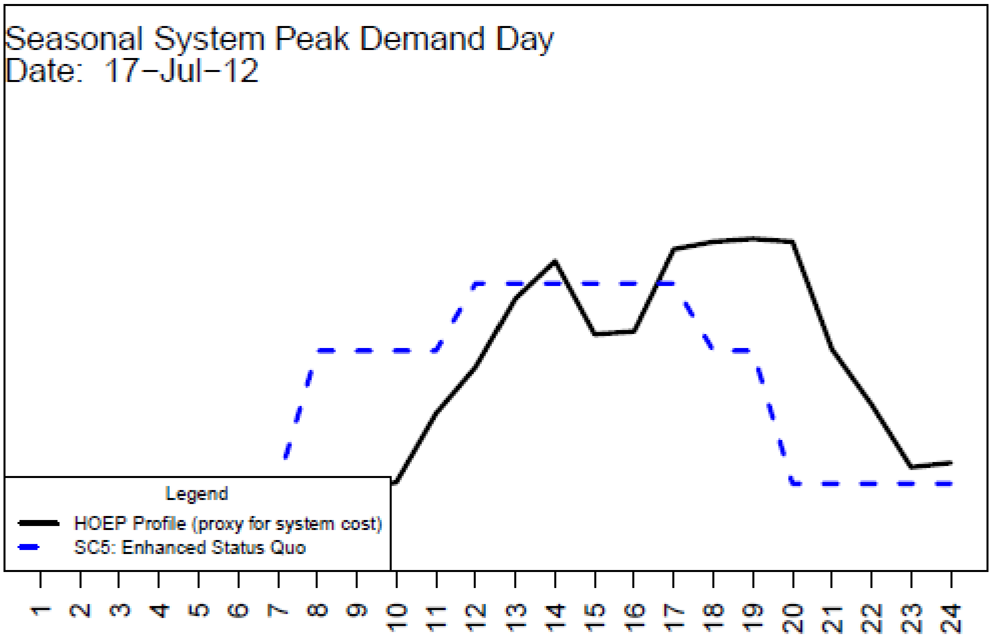
Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 91: The ESQ Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2011



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

Figure 92: The ESQ Scenario Price/Cost Alignment – Peak Demand Day, Test Year 2012



Source: IESO, OEB-provided hourly consumption data and Navigant analysis

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Appendix B – Estimated Residential Elasticities

The base elasticities used for the modeling outlined in this report were estimated in Part 1 of this study, and are presented below in Figure 93, below.

Figure 93: Part 1 Estimated Elasticities

		Elasticities				95% Conf. Intervals For Elasticities			
		Price Period							
Season	Commodity Period	On-Peak	Mid-Peak	Off-Peak 7pm - 9pm	Off-Peak Remainder	On-Peak	Mid-Peak	Off-Peak 7pm - 9pm	Off-Peak Remainder
Summer (Jun, Jul, Aug)	On-Peak	-0.34	0.35	0.04	-0.11	+/- 0.06	+/- 0.1	+/- 0.01	+/- 0.04
	Mid-Peak	0.39	-0.71	-0.05	0.32	+/- 0.08	+/- 0.13	+/- 0.01	+/- 0.05
	Off-Peak 7pm - 9pm	0.14	-0.13	-0.06	0.00	+/- 0.03	+/- 0.04	+/- 0.02	+/- 0.03
	Off-Peak Remainder	-0.05	0.13	0.00	-0.14	+/- 0.05	+/- 0.08	+/- 0.01	+/- 0.05
Summer Shoulder (May, Sept, Oct)	On-Peak	-0.09	-0.08	0.08	-0.02	+/- 0.06	+/- 0.08	+/- 0.01	+/- 0.03
	Mid-Peak	-0.08	-0.02	-0.08	0.07	+/- 0.06	+/- 0.1	+/- 0.01	+/- 0.04
	Off-Peak 7pm - 9pm	0.21	-0.22	-0.01	-0.09	+/- 0.03	+/- 0.04	+/- 0.03	+/- 0.03
	Off-Peak Remainder	-0.01	0.03	-0.01	-0.11	+/- 0.04	+/- 0.06	+/- 0.01	+/- 0.04
Winter (Dec, Jan, Feb)	On-Peak	-0.06	-0.08	0.02	-0.03	+/- 0.03	+/- 0.04	+/- 0.01	+/- 0.01
	Mid-Peak	-0.11	0.03	-0.01	-0.08	+/- 0.06	+/- 0.07	+/- 0.02	+/- 0.03
	Off-Peak 7pm - 9pm	0.06	-0.01	-0.12	-0.07	+/- 0.04	+/- 0.04	+/- 0.02	+/- 0.02
	Off-Peak Remainder	-0.02	-0.03	-0.01	-0.10	+/- 0.03	+/- 0.03	+/- 0.01	+/- 0.02
Winter Shoulder (Nov, Mar, Apr)	On-Peak	0.14	-0.24	0.01	0.10	+/- 0.04	+/- 0.05	+/- 0.01	+/- 0.01
	Mid-Peak	-0.33	0.50	-0.05	-0.11	+/- 0.06	+/- 0.09	+/- 0.01	+/- 0.03
	Off-Peak 7pm - 9pm	0.04	-0.10	0.03	0.04	+/- 0.03	+/- 0.03	+/- 0.02	+/- 0.02
	Off-Peak Remainder	0.05	-0.04	0.01	-0.01	+/- 0.03	+/- 0.03	+/- 0.01	+/- 0.02

Rows shaded in gray are not statistically significant at the 95% level.

Cells in boxes represent own-price elasticities. The remainder are cross-price elasticities.

Appendix C – Peak Demand Impacts with LTEP 2020 PV Production

The peak demand impacts discussed in the main body of this report are clearly sensitive to the shape of the overall IESO system demand profile (i.e., the transmission connected load profile). The current IESO system demand profile on peak days – what resembles a plateau – may not accurately reflect the shape of the demand profile in the years to come as increased distribution-connected solar photovoltaic (PV) penetration alters that load shape. This appendix re-examines the peak demand impact of each of the five scenarios in a case where the system demand profile has changed significantly as a result of increase solar PV penetration.

This appendix is divided into two sections:

Approach and Assumptions. This section outlines the assumptions, inputs and the manner in which they have been combined to create a simulated system demand profile that reflects a greatly increased solar PV penetration.

Peak Demand Impacts. This section outlines the estimated peak demand impacts where the system load profile has change significantly as a result of increased solar PV penetration.

The reader should be aware that this appendix is principally intended to be illustrative of the possible outcome of the five modeled scenarios should Ontario's solar PV production grow at the rate anticipated by the LTEP. As with any forecast, there remains considerable uncertainty regarding the true future magnitude of solar PV production profiles and levels.

Approach and Assumptions

The three principal inputs used by Navigant to model the effects of solar penetration were:

- The Ontario Ministry of Energy's *Long Term Energy Plan*[45](LTEP)
- The National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM)
- The Canadian Weather for Energy Calculations files

The SAM was combined with CWEC weather to create an average 24-hourly profile of PV output per month. This was then applied hourly across both test years 2011 and 2012 to develop an 8,760 profiles of PV production (in percentage terms) over each of these years. This profile was then applied to an estimated annual energy production number to obtain a distribution of forecast PV production in each hour of the two test years. The PV annual energy production number was estimated using data from the LTEP. This was done in the following manner.

1. Forecast annual PV production by 2020, net of 2013 forecast PV production was calculated (5 -1 = 4 TWh).

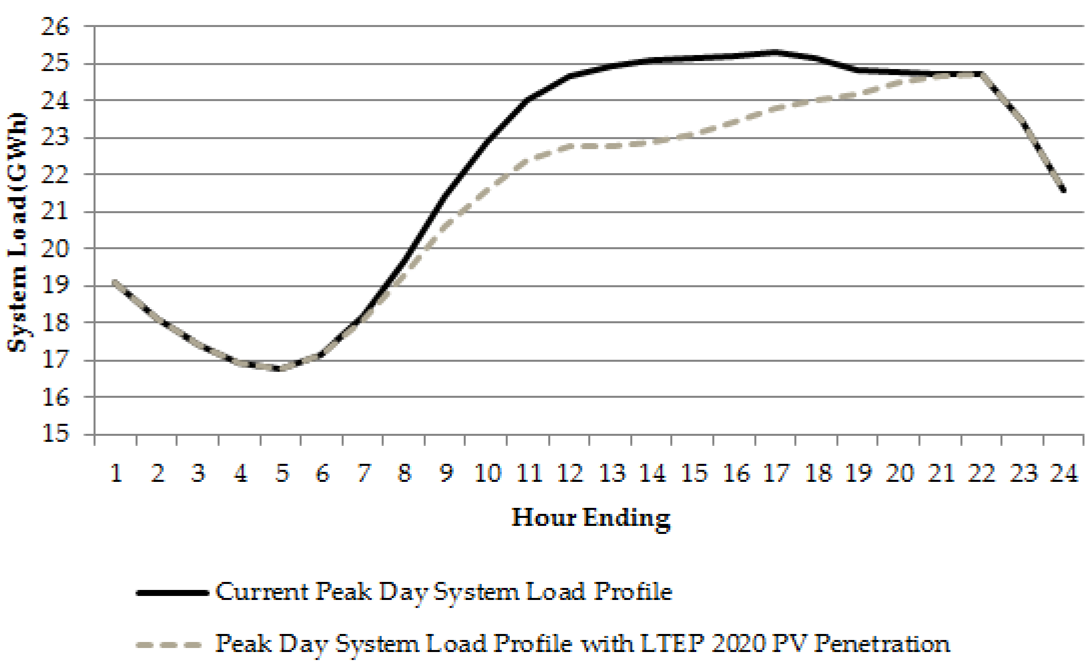
[45] The entire *Plan* as well as the underlying data are available online at: http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013

2. Forecast annual energy consumption in 2020, net of CDM and solar PV production was calculated (155 – 16.7 – 5 = 133 TWh).
3. A percentage was calculated by dividing 1 by 2.
4. This percentage was then multiplied by the forecast 2013 consumption used for Navigant's modeling.

This delivered an annual level of solar PV production that reflected forecast 2020 levels but was proportionate to the forecast 2013 levels of consumption used by Navigant for modeling peak demand impacts. This approach was taken to ensure that solar PV sensitivity system profiles were consistent with those used for the main analysis, above.

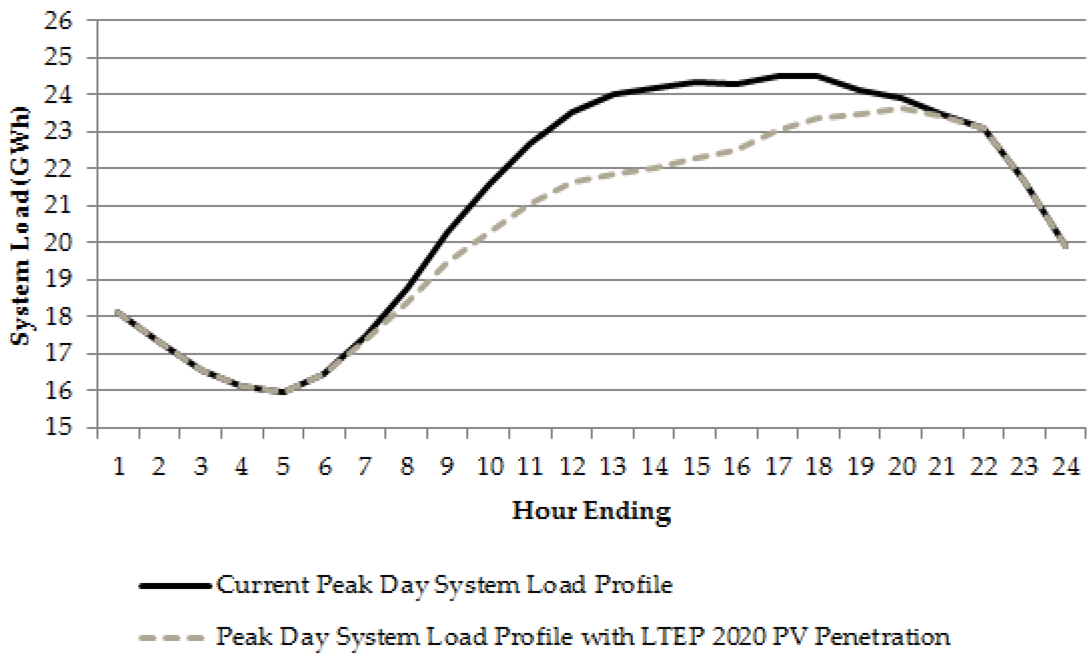
Once this annual PV energy level was applied to the estimated PV production profile, this profile was subtracted from the current system demand profile used by Navigant in its modeling, delivering an hourly system demand profile reflecting the relative level of solar PV penetration forecast by the LTEP for 2020.

Figure 94: Comparison of Actual and Forecast PV Peak Day Load Profile (Test Year 2011)



Source: IESO, OEB, CWECs, NREL and Navigant analysis

Figure 95: Comparison of Actual and Forecast PV Peak Day Load Profile (Test Year 2011)



Source: IESO, OEB, CWECs, NREL and Navigant analysis

Before examining how the estimated peak demand impacts of each scenario have changed, it is worth examining the effect that including the LTEP forecasted relative levels of PV production by 2020 have had on the existing system load profile on the number one peak day from the two test years used in the analysis. These are shown below in Figure 94 and Figure 95.

Note that the principal effect of increased PV production is to reduce net system load demand during the daylight hours – effectively eliminating the "plateau" of peak demand. There is now a larger differential between the demand in each of successive top ten peak demand hours, and the peak hours of the peak day are clearly much later in the day – between 7pm and 10pm as opposed to between 11am and 6pm.

Peak Demand Impacts

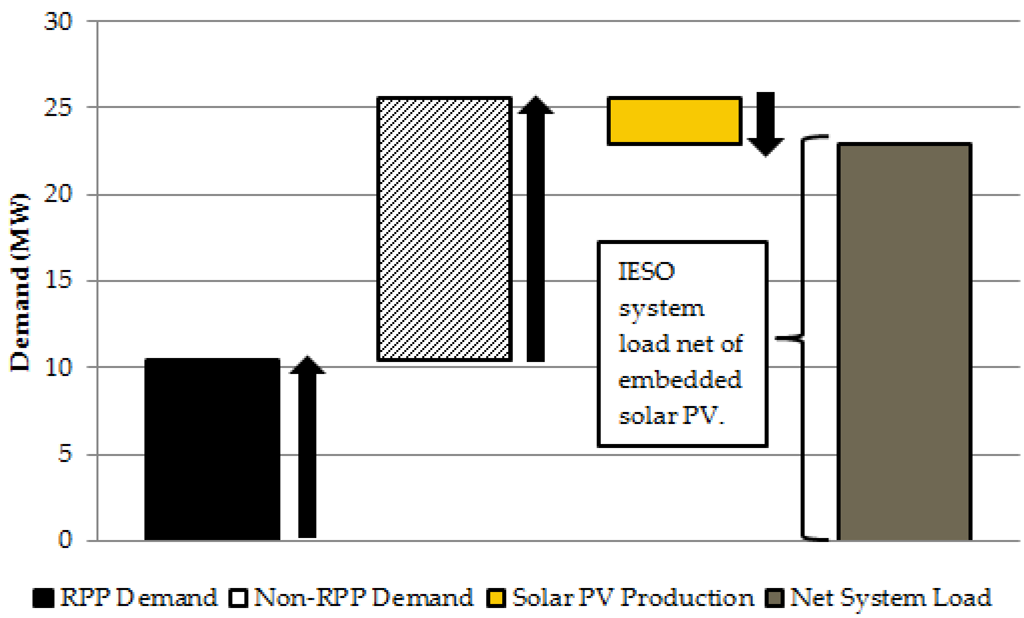
This section of the appendix provides the estimated system peak demand impact (as defined above) of each of the five scenarios in the case when the IESO system load shape reflects the LTEP's forecast of solar PV production (relative to demand) by the year 2020.

Understanding Why PV Penetration Affects Scenario Peak Demand Impacts

The fact that an increase in solar PV production could somehow affect IESO system peak demand is inherently count-intuitive – why would an increase in solar PV affect electricity demand? The key to understanding this effect is that solar PV affects *net* system load, but not end-use consumption.

That is, electricity consumption (end-use consumption) does not change, but what happens is that embedded solar PV production serves some portion of that demand. Thus, the net system demand (total demand, net of PV production) is changed by solar PV production. This process is illustrated in Figure 96, below.

Figure 96: Illustration of Net System Load



Source: IESO, OEB, CWECs, NREL and Navigant analysis

Note that the effect of the various TOU scenarios on the black column (RPP end-use demand) is unaffected by solar PV production. That is, the impact of each TOU scenario on RPP demand in each hour of the year will be identical for both this sensitivity analysis as it is for the principal analysis in the body of this report.[46]

However, system peak demand is defined by the net system load, not the RPP demand. This means that the top ten hours of system peak demand in the principal analysis Status Quo *may not be the same* as the top ten hours of system peak demand in this solar PV sensitivity analysis Status Quo. This in turn means that the sensitivity analysis Status Quo peak demand may not be the same as the principal analysis Status Quo peak demand and so it follows that the peak demand impact of each scenario may not be the same for the sensitivity analysis as for the principal analysis. In fact, the peak demand impacts are not the same as may be clearly seen in the sub-sections that follow.

[46] The exception to this would be if increased solar PV significantly affects the order of days with the highest demand, since this would affect when CPP and CPD events were called. In this case, however, additional solar PV has not affected when CPP and CPD events would be called.

Summary of LTEP Forecast PV Sensitivity Analysis Peak Demand Impacts

The change in system peak demand profile discussed above has a significant effect on the peak demand impacts of the five scenarios modeled. The changes in impacts are driven by two factors:

1. with increased solar PV penetration, the highest demand hours of the peak demand day occur between 7pm and 10pm; and
2. in all but one of the scenarios modeled (the CPD Scenario), this period is subject to the lowest price incenting customers to *increase* consumption in this period.

Unsurprisingly, in this sensitivity analysis only the CPD Scenario delivers consistent demand reductions across both test years, as shown below in Figure 97.

Figure 97: Estimated System Peak Demand Impact (MW) – With LTEP 2020 Forecast PV

Test Year	Scenario 1 (CPP)	Scenario 2 (Flat)	Scenario 3 (Super-Peak)	Scenario 4 (CPD)	Scenario 5 (ESQ)
2011	15	25	443	-50	50
2012	2	-38	133	-75	166
Average	**9**	**-6**	**288**	**-63**	**108**
Rank:	**3**	**2**	**5**	**1**	**4**

NB: assumes 5% residential and 2.5% GS participation for Scenarios 1 and 4.

Source: IESO, OEB, CWECs, NREL and Navigant analysis

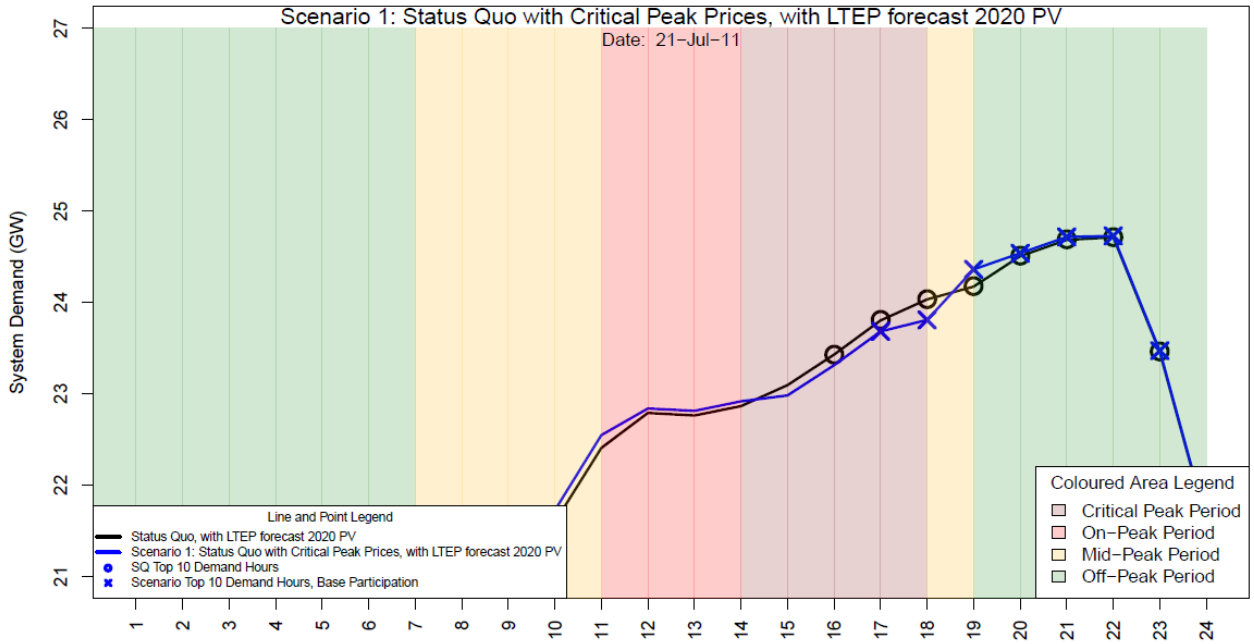
Although the Flat Scenario delivers a small demand reduction in test year 2012, the fact that it does not do so in both test years suggests that the impact is not significant and is driven by the underlying "noise" of the various data-generating processes at work.

The sub-sections below discuss the estimated peak demand impacts of each scenario under the assumption of LTEP 2020 PV penetration in more detail, and provide plots of the system peak day.

Scenario 1: Status Quo with Critical Peak Pricing

Figure 98 below shows the Status Quo hourly system demand in the test 2011 peak day (21 July) with the LTEP 2020 PV assumptions imposed. It also shows the impact on that system demand of the CPP Scenario with the base assumed levels of participation (5% residential and 2.5% GS). Note that with the new PV-modified system load shape the CPP period is fundamentally mis-targeted and results in demand being shifted toward the hours of highest demand – those immediately following the CPP period. Note that in the CPP Scenario the critical peak period was restricted to the On-Peak and Mid-Peak periods. An alternative structure that allows the CPP event to be called during any hour of the day would deliver a different impact.

Figure 98: System Peak Demand Impact, CPP Scenario with LTEP 2020 PV



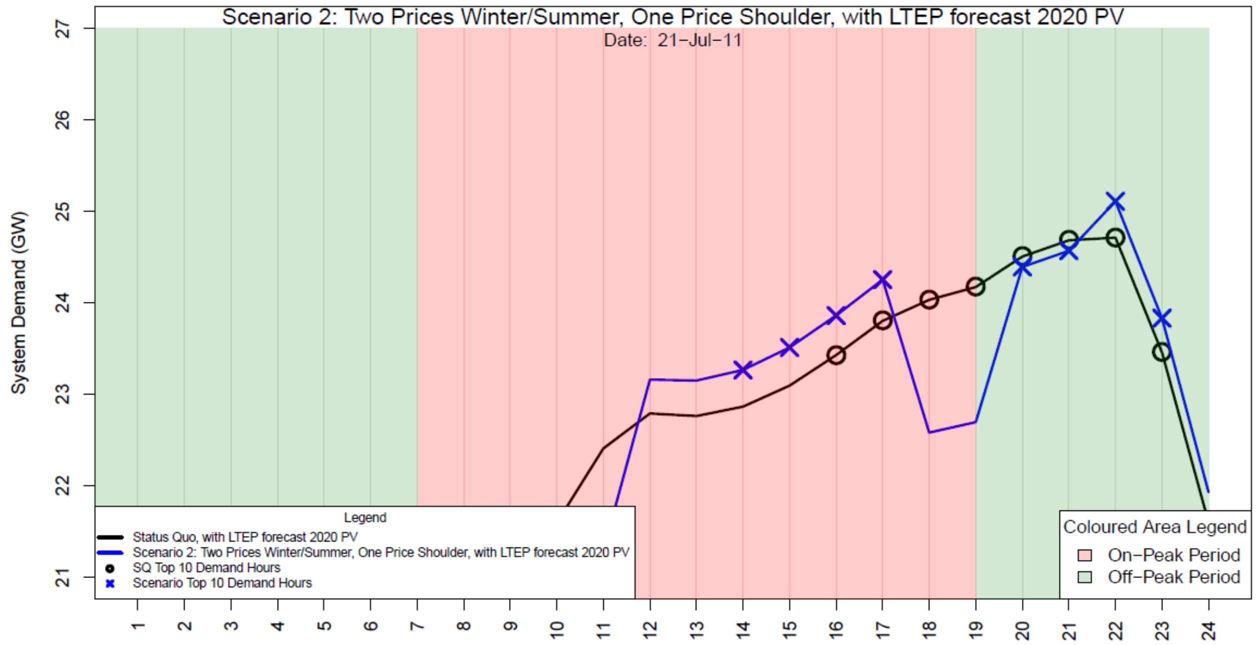
Source: IESO, OEB, CWECs, NREL and Navigant analysis

Scenario 2: Two Prices Winter/Summer, One Price Shoulder

Figure 99, below shows the impact on LTEP 2020 PV-modified system peak demand of the Flat Scenario on the peak day of test year 2011. Recall from Figure 97 that this scenario resulted in an increase in system peak demand for test year 2011 and a decrease for test year 2012.

The late afternoon demand reductions (occurring in the Status Quo afternoon Mid-Peak period of 5pm – 7pm) are insufficient to offset either the demand increases in the earlier part of the afternoon or the demand increases in the evening hour (9 to 10pm) that is now the single highest demand hour of the year, resulting in an increase in system peak demand.

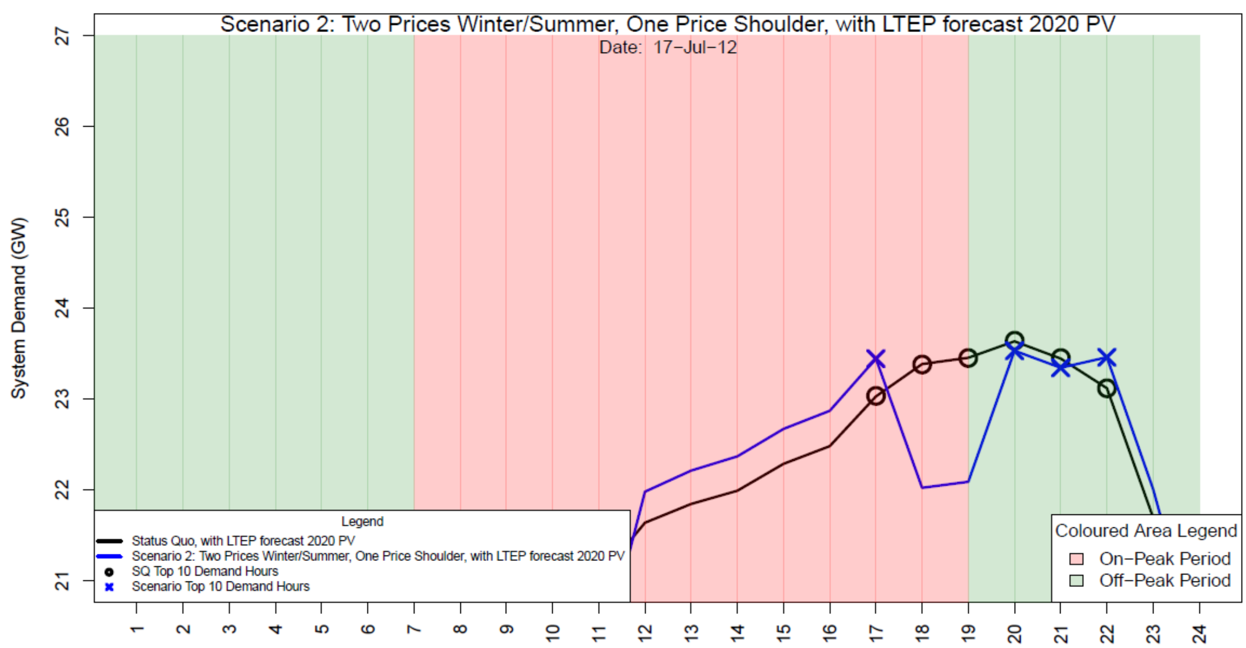
Figure 99: System Peak Demand, Flat Scenario with LTEP 2020 PV – Test Year 2011



Source: IESO, OEB, CWECs, NREL and Navigant analysis

Figure 100, below, shows impact of the Flat Scenario on the peak demand day in test year 2012, the test year in which this scenario resulted in a demand reduction.

Figure 100: System Peak Demand, Flat Scenario with LTEP 2020 PV – Test Year 2012



Source: IESO, OEB, CWECs, NREL and Navigant analysis

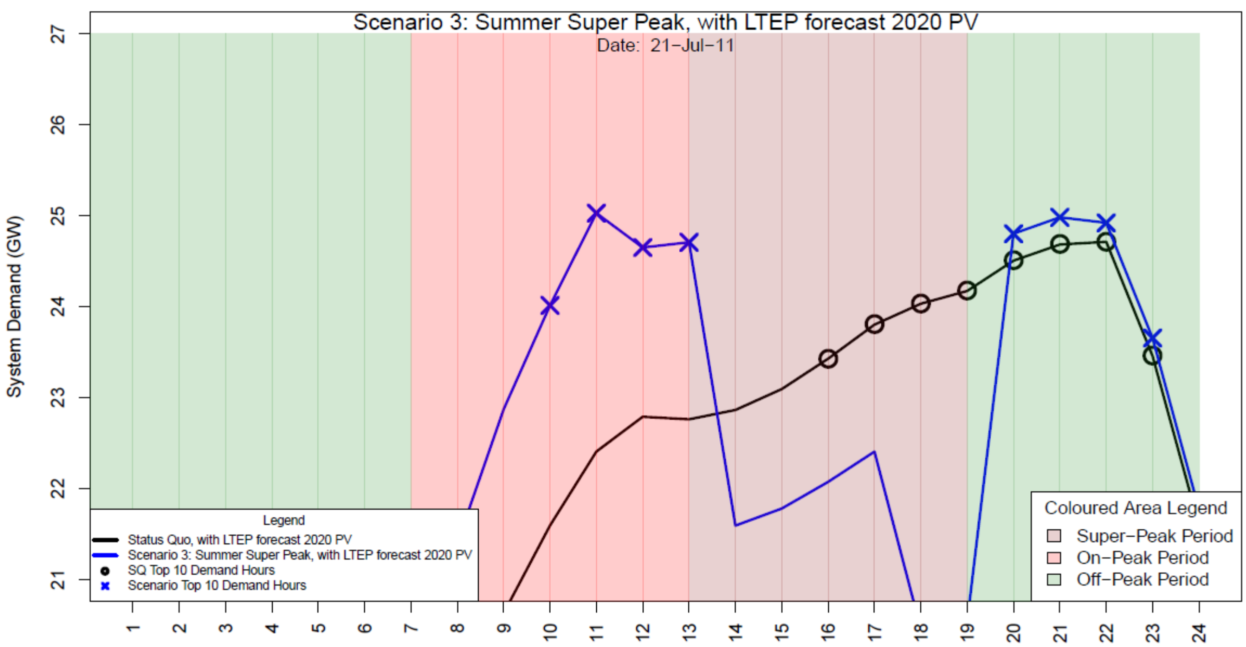
In the case of test year 2012, it can be clearly seen that the demand reduction in the Status Quo Mid-Peak period (5pm – 7pm) is sufficient to compensate for the slight increase in demand provoked by the scenario earlier in the afternoon and later at night.

From both Figure 99 and Figure 100 it is clear that the Flat Scenario is fundamentally unsuited to the new PV-modified load profile, targeting, as it does, the hours between 7am and 7pm and incenting additional consumption from 7pm to 10pm when the highest system peak demand hours of the year occur.

Scenario 3: Summer Super-Peak

Figure 101, below shows the impact on LTEP 2020 PV-modified system peak demand of the Super-Peak Scenario on the peak day of test year 2011. As in the principal analysis, the significant contrast between prices in the On-Peak (7am to 1pm) and Super-Peak period (1pm to 7pm) and the large drop in price in the On-Peak period from the Status Quo, lead to a very large shift in demand to the morning hours, resulting in a net increase in system peak demand. Likewise, consumption is shifted to the evening Off-Peak period – the period in which, under this sensitivity analysis system demand is highest. The combination of these two effects yields an increase in overall system peak demand, as in the principal analysis above.

Figure 101: System Peak Demand, Super-Peak Scenario with LTEP 2020 PV

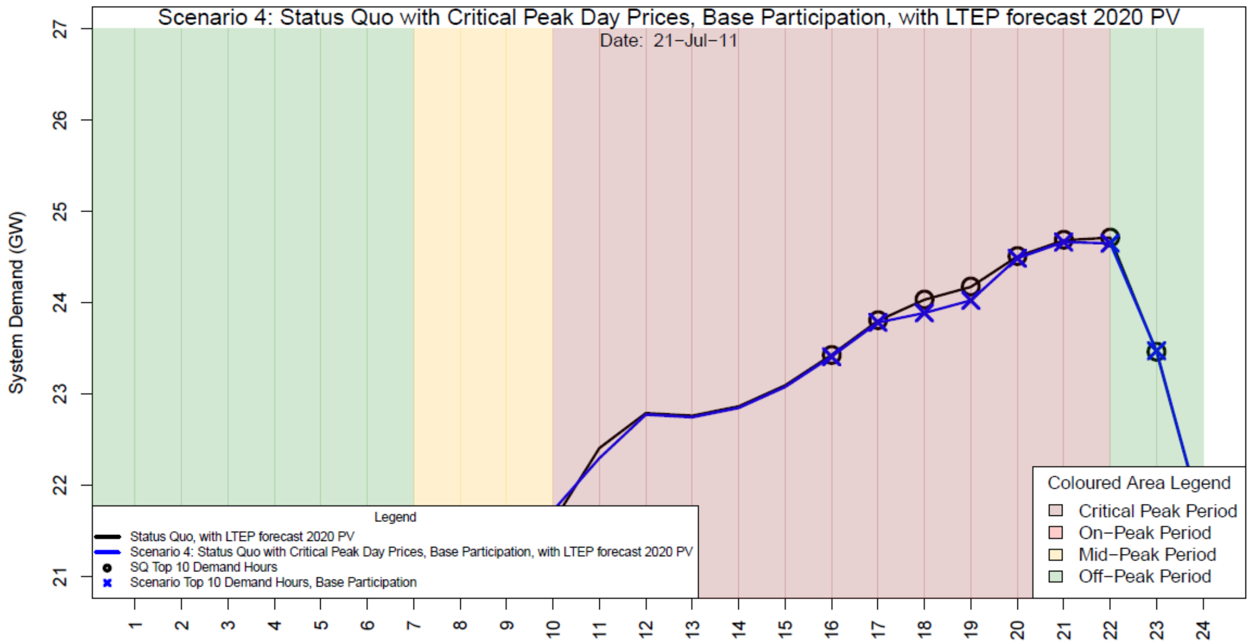


Source: IESO, OEB, CWECs, NREL and Navigant analysis

Scenario 4: Critical Peak Day

Figure 102, below shows the impact on LTEP 2020 PV-modified system peak demand of the CPD Scenario on the peak day of test year 2011. Note that the critical peak event period (10am – 10pm) covers nearly all of the system peak demand hours, and definitely covers the highest six of the top ten peak demand hours. This means that compensating shifting to adjacent periods does not push up the system peak demand. Although some of the other scenarios had larger estimated demand reductions in individual hours, they also had large compensating demand increases in other hours that overwhelmed demand reductions. The CPD Scenario on the other hand has no such overwhelming demand increases.

Figure 102: System Peak Demand, CPD Scenario with LTEP 2020 PV

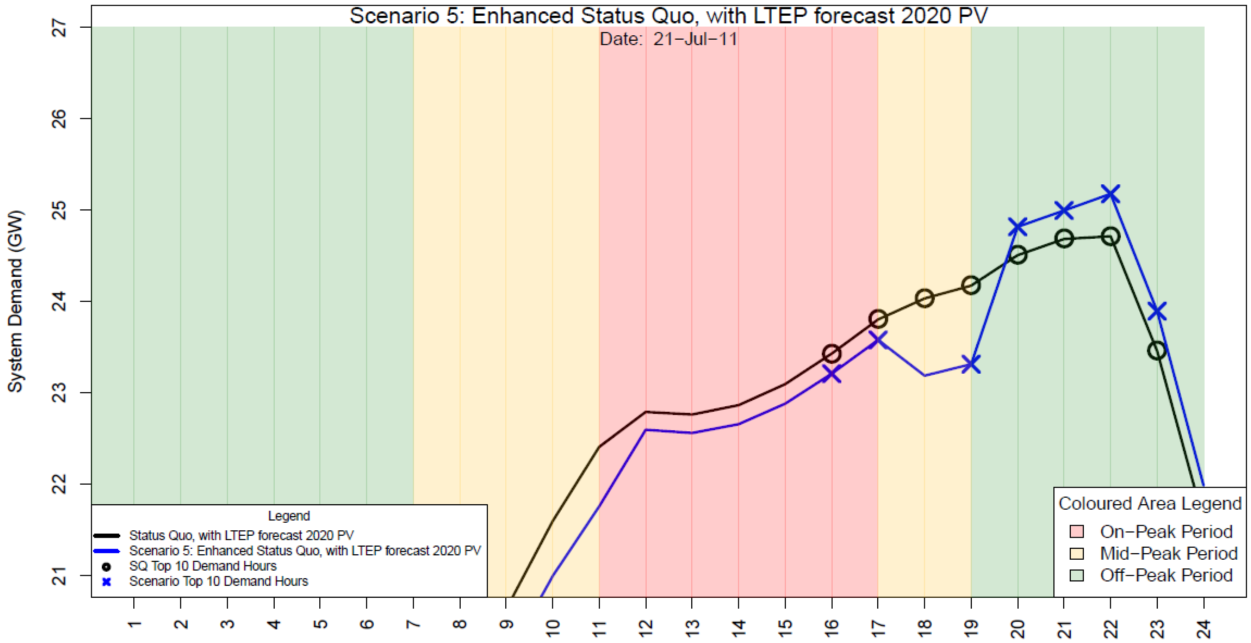


Source: IESO, OEB, CWECs, NREL and Navigant analysis

Scenario 5: Enhanced Status Quo

Figure 103, below shows the impact on LTEP 2020 PV-modified system peak demand of the ESQ Scenario on the peak day of test year 2011. As with many of the other scenarios the TOU structure of the ESQ Scenario provides an incentive for customers to increase their consumption in the 7pm to 10pm period, a period which, in this sensitivity analysis, is now coincident with the highest hours of system peak demand. This results in a net increase in system peak demand.

Figure 103: System Peak Demand, ESQ Scenario with LTEP 2020 PV



Source: IESO, OEB, CWECs, NREL and Navigant analysis