RP-2007-0706

Enersource Mississauga Hydro Inc.

November 27, 2007

INDEX

Board Staff Technical Conference Questions

OPERATING REVENUE

Board Staff Technical Conference Question # 1

Reference: Exhibit B/Schedule 2/Tab 5a, Board Staff Interrogatory No. 23

OTHER REVENUE
(000's)

	2006 EDR
LATE PAYMENT CHARGES	404
CUSTOMER SERVICE CHARGES	1,123
RETAIL TRANSACTION HUB/MKT PARTICIPANT CHG	283
MISCELLANEOUS REVENUE	276
TOTAL OTHER REVENUE	**2,086**
CUSTOMER SERVICE CHARGES	
RENTAL INCOME	280
COLLECTION CHARGES	154
RECONNECTION CHARGES	21
SET UP CHARGES - RESIDENTIAL	483
NSF SERVICE CHARGES	48
TEMPORARY SERVICE INSTALLATION	56
LETTER OF REFERENCE	18
CREDIT CHECK	53
OTHER MISCELLANEOUS CHARGES	10
	1,123

Please provide an explanation as to why the number for "Miscellaneous Revenue" (i.e. $276) is different from the 2006 Board Approved, Sheet 5-5, Cell D22 - $2,056,959.

Response: 1.

The number for "Miscellaneous Revenue" is different than the 2006 Board Approved, Sheet 5-5, Cell D22 because these numbers are not comparable. In the 2006 Board Approved, Sheet 5-5, EHM reduced its revenue requirement for revenue offsets as follows:

SHEET 5-5: Revenue Offsets: (000's)	(000's)
Board Approved Charges	
Specific Service Charges ***(from Sheet 5-2)***	**1,123**
Late Payment Charges ***(from Sheet 2-4 ADJUSTED ACCOUNTING DATA)***	**404**
Other Distribution Revenue ***(from Sheet 5-3)***	**283**
Other Income & Deductions ***(from Sheet 2-4 ADJUSTED ACCOUNTING DATA)***	**2,057**
TOTAL REVENUE OFFSETS	**3,867**

In EHM previous response to Board Staff Interrogatory #23, EHM provided the 2006 Board Approved Other Revenue excluding interest income of $2,806. 2006 Board Approved interest income is $1,781.

RATE BASE

Board Staff Technical Conference Question # 2

Reference: Exhibit C/ Schedule 3/ Tab 3

More detail is needed to evaluate the land purchase.

a. How big is the land being purchased

b. Is it presently vacant or does it have buildings on it

c. Is the purchase a related party transaction

d. How was the purchase price arrived at

e. Why would a satellite location be more expensive and disruptive to the organization

Response: 2. a-e)

A) The land in question is approximately 2.8 acres.

B) The land is presently not vacant.

C) The property is owned by the Region of Peel which is not a related party.

D) At this point the Region is in the preliminary stages of selling the property and is looking at approximately $750k per acre. The additional $400k is related to preparing the property for Enersource usage.

E) A satellite location would be more expensive and disruptive due to the loss of synergies that an adjacent property presents to Enersource. Costs that could be absorbed through Enersource's current infrastructure could not be utilized in a satellite facility. For instance, separate security infrastructure and personnel and the costs in terms of transporting equipment and personnel commuting to a satellite location.

Another detriment in a satellite location with regard to commuting is lost time in emergency response situations. Proximity to our current location is vital.

The land is required for parking, pole storage, and handling, waste bins and the

opportunity to reconfigure the entrance and exit to 3240 Mavis Road.

Board Staff Technical Conference Question # 3

Reference: More detail is needed to evaluate the rolling stock purchases for 2008

a. What vehicles are being replaced – a 2008 listing like the one on page 30 of the 2007 System Capacity report would be helpful

b. What are the estimated unit costs?

c. How are vehicles purchased?

d. How are old vehicles disposed off?

Response: 3. a-d)

a) The vehicles being replaced are shown in the table below, a similar report to that shown on page 30 of the 2007 System Capacity Report:

Rolling Stock for 2008 Test Year

Type (a)	Unit # (b)	Year (c)	Replacement Cycle (d)	Year to Replace (e)	Estimated Unit Cost ($) (f)
Car	2105	2005	3	2008	$47,200
Car	2205	2005	3	2008	$47,200
Car	2305	2005	3	2008	$47,200
Car	3300	2000	5	2005	$25,000
Car	3400	2000	5	2005	$25,000
Bucket Truck	20297	1997	10	2007	$200,000
Bucket Truck	20495	1995	12	2007	$372,400
Bucket Truck	20697	1997	10	2007	$200,000
Bucket Truck	21099	1999	9	2008	$190,000
Van	31199	1999	7	2006	$120,000
Pickup Truck	41603	2003	5	2008	$35,000
Pickup Truck	42103	2003	5	2008	$35,000
Pickup Truck	42703	2003	5	2008	$35,000
Pickup Truck	42903	2003	5	2008	$35,000
Pickup Truck	45300	2000	7	2007	$40,000
Mini Van	51601	2001	5	2006	$25,000
Mini Van	51701	2001	5	2006	$55,000
Mini Van	51801	2001	5	2006	$55,000
Van	53900	2000	7	2007	$55,000
Sweeper	90794	1993	15	2008	$70,000
Off Road access vehicle	New		5	2008	$15,000
Kubota Trailer	92295	1995	13	2008	$12,000
Cargo Trailer	94188	1988	12	2000	$19,000
Air Compressor	97390	1990	18	2008	$20,000
Air Compressor	97490		18	2008	$20,000

Hydraulic Tools & Service Equipment	2105	$57,600
Total Estimated Cost		**$1,857,600**

b) The estimated unit costs for replacement vehicles are shown in column (f) – Estimated Unit Costs in the above table.

c) All Vehicle purchases conforms to our Purchasing Policy. The following outlines the requirements in our Purchasing Policy:

At least three competitive quotes are to be obtained for significant purchases and a formal tendering process is to be followed for purchases over $50,000. A single source document is required when less then 3 quotes have been obtained. Normally, all purchases over $5000 must have three quotations, but the organization recognizes that there may be situations where the only method of procurement will be through a single source vendor.

d) Old vehicles are disposed off in accordance with the following:

1) **Our policy with respect to the disposal of vehicles ensures that Enersource receives fair market value for the resale of vehicles**
2) **Executive vehicles will first be offered to the current driver at fair market value**
3) **Executive vehicles not purchased by the current driver will be sold at fair market value by way of auction**
4) **All executive vehicle purchase transactions will be performed through an independent third party**
5) **All other vehicles that have reached the end of their useful life will be sold at fair market value by way of auction**
6) **All vehicles will be sold on an as is basis (not certified or emission tested)**

Board Staff Technical Conference Question # 4

Reference: Integration of GIS and SCADA Systems

a. What are the main benefits of marrying these two systems together?

b. If eliminating manual systems of putting pins in maps to record switch status is the main benefit how does EHM propose to deal with computer failures that would leave operators blind? If the manual system is going to be maintained to hedge against this possibility what savings will actually result?

c. SCADA already keeps track of switch status for any automated switches. What is benefit of computer tracking of switch status for manually operated switch points?

d. If modelling of system condition prior to making a switching operation is the benefit, can't the GIS already do this without having to be connected to the SCADA?

Response: 4. a)

The 4 main benefits to the integration of these two systems includes:

Ability to complete our Disaster Recovery Plan by having the real-time status of our distribution network available at our DR site. Presently, should we have a fire or and evacuation of our main office, we would not have the real time status of our distribution network at the DR site as it is on paper maps.

Establish a single Interface to operate the distribution network. Presently, the System Operator uses multiple systems to accomplish this task. This will allow for safer operation of our distribution network as the System Operator will interface with one system.

Eliminate the swing board paper maps in the System Control Centre

The fact that System Control does not completely rely on the AM/FM/GIS data impacts the overall quality of that data. If it is not their primary data source, there is less impetus for them to seek out and identify errors in it, and the full benefits of their involvement with the model are not realized throughout the rest of the engineering departments. The impact of having more accurate/faster update of the AM/FM/GIS data will provide for more accurate and more timely GIS data to other departments within the company.

Response: 4. b)

The integration of the GIS and SCADA systems will be done by means of installing and configuring a commercial software application which offers 24 x 7 availability. This availability is made possible through a redundant hardware configuration, and advanced software functionality. Redundant servers are installed, each of which contains an identical, live copy of the database. All modifications to the database are executed simultaneously on both servers through a software process called "replication". If the primary server fails for any reason, operation can continue uninterrupted on the secondary server. After the primary server has been repaired, the databases can be synchronized without taking either database offline or significantly impacting operations in any other way.

With the back up of hardware and software systems, there are no plans in maintaining paper maps as backup.

Response: 4. c)

By modeling our entire distribution network, ie status of all devices, we will be able to take advantages of:

Performing real-time load flows, reducing the chance of switching errors

Performing real-time loss minimization to increase distribution network efficiencies

Documenting/tracking Work Protection for our crews on the system will enhance safety. Now, there is a potential of Work Protection pins falling off our paper maps.

Tracking the amount of times specific devices are operating will help us focus our maintenance programs.

Response: 4. d)

The GIS system is used to model our distribution system; however, it is not real-time. The benefit of modeling the system in a real-time environment will allow our System Operators to test switching before they actually perform the switching. This will be very beneficial during emergencies and storm condition so that we do not overload adjacent devices.

OPERATING COSTS

Board Staff Technical Conference Question # 5

Reference: Exhibit J Schedule A Page 37 of 106, Board Staff Interrogatory No. 24 - Distribution Expenses Incurred Through the Purchase of Services or Products

Please provide specific confirmation that the only distribution expenses it incurs through the purchase of services or products are done through Enersource Corporation, as stated in the response, and that Enersource Hydro Mississauga (EHM) itself does not contract directly with any third parties for any such services (e.g consulting services, building maintenance services etc). If Enersource Hydro Mississauga does incur costs for any such services directly, please provide the information requested in the interrogatory for such services.

Response: 5.

Enersource is unable to provide a written response due to limited time and resources.

Board Staff Technical Conference Question # 6

Reference: Exhibit J Schedule A Page 38 of 106, Board Staff Interrogatory No. 25 - Shared Services

Enersource's forecast of a management fee of $8.243 million for shared services is discussed. (i) Please provide the amount of this fee for 2006 actual and Board approved, 2007 bridge as well as the recovery amounts for the same years to support the net amounts shown as "Management Fees/Recoveries," as shown in Exhibit D Schedule 2 Tab 1. Please provide a clear explanation as to why Enersource accounts for these fees in the manner. Please also explain the change in the amounts of these fees relative to what was filed in the 2006 application, wherein Schedule 6-9 showed Management Fees of $15.8, $17.5 and $17.4 million for 2002, 2003 and 2004 respectively and why they are now so much lower. Also relative to Schedule 6-8, Distribution Expenses Paid to Affiliates.

Please also provide total annual expense by service as shown in this interrogatory response for 2008 in the same format for each of 2006 actual and Board approved and 2007

For (iii), which is the rationale and the cost allocators used for shared costs, for each type of service, please provide a fuller and more detailed response by service. Please state which services use which cost driver and why, as requested in the interrogatory. Exhibit D/Schedule 1/Tab 11/page 2 of 6 also does not provide a sufficiently detailed breakdown or explanation

Response: 6.

Enersource accounts for managements fees by way of allocations because the costs associated with corporate functions do not benefit only the operations of Enersource Hydro Mississauga.

See Attachment.

Management Fees: paid to Enersource Corporation

Board # 6	Driver	'07 & '08 Alloc %	2008 Test yr.	2007 Bridge yr.	2006 Alloc %	2006 Actual	2006 Budget Alloc %	2006 Budget
Enersource Hydro Mississauga:								
Corporate Goverance	Time Estimate	90.00%	189	270	90.00%	391	90.00%	369
Executive Management and Communications	Time Estimate	90.00%	2,012	2,195	90.00%	2,000	90.00%	2,097
Safety	Time Estimate	90.00%	654	600	90.00%	831	90.00%	276
Human Resources	Headcount	92.00%	1,008	944	88.00%	769	88.00%	706
Finance	Time Estimate	80.00%	3,050	3,150	80.00%	2,486	80.00%	3,039
Purchasing	Time Estimate	90.00%	138	146	90.00%	135	90.00%	137
Legal	Time Estimate	30.00%	96	96	30.00%	52	30.00%	129
Enersource Hydro Charges	Historical	85.00%	705	569	85.00%	674	82.02%	481
Capital Taxes	Historical	85.00%	20	20	85.00%	15	82.02%	23
Other Expense/Financial Income/Other Income	Historical	85.00%	371	394	85.00%	449	82.02%	674
Total Management Fee			$ 8,243	$ 8,383		$ 7,802		$ 7,930

Total Enersource Corporation costs	2008 Test Yr	2007 Bridge Yr	2006 Actual	2006 Board approved budget
Corporate Goverance	210	300	434	410
Executive Management and Communications	2,235	2,438	2,222	2,330
Safety	727	667	924	307
Human Resources	1,095	1,027	874	802
Finance	3,814	3,937	3,108	3,799
Purchasing	153	162	150	152
Legal	320	319	175	429
Enersource Hydro Charges	829	669	793	586
Capital Taxes	24	24	17	28
Other Expense/Financial Income/Other Income	437	464	528	822
	9,845	10,006	9,225	9,664

Facilities and Information Systems Recoveries: Received from Enersource Corporation and Hydro Mississauga Services

Board # 6

	2008 Test Yr	2007 Bridge Yr	2006 Actual*	2006 Budget	
Facilities costs to Enersource Hydro Mississauga	$ 1,948	$ 1,785	$ 1,539	$ 1,488	
Information Systems costs to Enersource Hydro Mississauga	$ 3,067	$ 2,838	$ 2,139	$ 2,224	
Driver					
HEADCOUNT:					
Enersource Hydro Mississauga	323	317	279	297	
Enersource Telecom	-	-	-	12	
Enersource Corporation	47	47	41	43	
Enersource Hydro Mississauga Services	20	15	17	13	
	390	**379**	**337**	**365**	
Facilities Costs Recoveries	$ -	$ -	$ -	$ 49	From Enersource Telecom
Facilities Costs Recoveries	$ 235	$ 221	$ 187	$ 175	From Enersource Corporation
Facilities Costs Recoveries	$ 100	$ 71	$ 78	$ 53	From Enersource Hydro Mississauga Services
Information Systems Costs Recoveries	$ -	$ -	$ -	$ 73	From Enersource Telecom
Information Systems Costs Recoveries	$ 370	$ 352	$ 260	$ 262	From Enersource Corporation
Information Systems Costs Recoveries	$ 157	$ 112	$ 108	$ 79	From Enersource Hydro Mississauga Services

Return on Assets: Received from Enersource Corporation and Hydro Mississauga Services

	2008 Test Yr	2007 Bridge Yr	2006 Actual*	2006 Budget
	CO#10	CO#10	CO#10	CO#10
Assets values to be allocated	27,935	18,356	16,083	20,960
Driver				
HEADCOUNT:				
Enersource Hydro Mississauga	323	317	279	297
Enersource Telecom	-	-	-	12
Enersource Corporation	47	47	41	43
Enersource Hydro Mississauga Services	20	15	17	13
	390	**379**	**337**	**365**
Asset allocation based on Headcount				
Enersource Telecom				689
Enersource Corporation	3,367	2,276	1,957	2,469
Enersource Hydro Mississauga Services	1,433	726	811	747
Return on Investment Rate:	7.464%	7.464%	6.000%	6.000%
Return on Investment Recovery from:				
Enersource Telecom				**$ 40**
Enersource Corporation	**$ 251**	**$ 170**	**$ 117**	**$ 148**
Enersource Hydro Mississauga Services	**$ 107**	**$ 54**	**$ 49**	**$ 45**

* Please note: 1) the 2006 values presented here are only estimates of the actual 2006 values based on an annualized average headcount. Throughout the year asset value and headcount fluctuations would create variances from these values. The actual Return on assets for 2006 was $196 (2005 - $265). 2) The 2007 Headcount values were also annualized for Return on Assets recovery.

Board #6	2008 Test Yr	2007 Bridge Yr	2006 Actual	2006 Budget
Management Fees	$ 8,243	$ 8,383	$ 7,802	$ 7,930
Facilities Recoveries	(335)	(292)	(265)	(277)
Information System Recoveries	(527)	(464)	(368)	(414)
Other Recoveries	(6,624)	(7,417)	(7,507)	(8,139)
	$ 758	**$ 210**	**$ (338)**	**$ (901)**

The methods of recovering expenses applied at Enersource were determined by management to most accurately reflect costs as they occurred by company. In short, these methods are considered the best drivers of the expense.

The change in Management fees from 2002, 2003 and 2004 where they were incurred at $15.8, $17.5 and $17.4 million to the values reported above is due to the realignment ir 2006 of several Business Units from Enersource Corporation to Enersource Hydro Mississauga. The units in question were determined to function for the benefit of Hydro Mississauga only, and as such were not Corporate functions.They are as listed below:

Customer Service Admin
Energy Services
Customer Accounts
Customer Billings
Information Services Admin
Computer Operations
AM/FM
Corporate Records
Stores

Those Management Fee services that are allocated based on Time Estimates are done so because that is the best driver of the expense per company. For instance, Legal fees, Safety and Corporate governance costs are driven by time spent by those Business functions in each company. Human Resources allocation is based on Headcount because most of the costs generated in Human Resources, such as interviewing, benefits administration etc, are based on a per employee headcount basis.Capital taxes and Other expenses/Income are based on historical experience because those are the best drivers of those expenses.

Board Staff Technical Conference Question # 7

Reference: Exhibit J Schedule A Page 38 of 106, Board Staff Interrogatory No. 25 - Corporate Cost Allocation

Re: Exhibit J Schedule A Page 38 of 106, Interrogatory #25, part (iv) the response is insufficiently detailed, stating that “Enersource’s overall methodology is to charge each affiliate an appropriate share of corporate overhead costs. Enersource Corporation allocates actual costs to each affiliate based on the budgeted allocation percentage.”

Please state how an “appropriate” share is determined and a more detailed explanation as to how and why actual costs are allocated to each affiliate based on the budgeted allocation percentage.

It would be helpful if Enersource would review its response in this area in the context of the filing guidelines, which describe corporate cost allocation as “an allocation of costs for corporate and miscellaneous shared services from the parent to the utility. This is not to be confused with the allocation of the revenue requirement to rate classes for the purpose of rate design.” The filing guidelines require that the applicant provide “a detailed description of the assumptions underlying the allocation of these services” and documentation of its overall methodology

Response: 7.

The netting of recoveries and management fees was only for presentation purposes in Exhibit D/Schedule 1/Tab 11/Page 1. The description of each type of OM&A expense recovery can be found in Exhibit D/Schedule 1/Tab 11/Page 2 through 6.

Enersource accounts for managements fees by way of allocations because the costs associated with corporate functions do not benefit only the operations of Enersource Hydro Mississauga.

Answers to Board Staff Technical Conference Question 6						
Items Paid to/Received from affiliates: (1) Management Fees: paid to Enersource Corporation						
	Driver (B)	'07 & '08 Alloc %	2008 Test yr.	2007 Bridge yr.	2006 Alloc %	2006 Actual
Enersource Hydro Mississauga:						
Corporate Goverance	Time Estimate	90.00%	189	270	90.00%	391
Executive Management and Communications	Time Estimate	90.00%	2,012	2,195	90.00%	2,000
Safety	Time Estimate	90.00%	654	600	90.00%	831
Human Resources	Headcount	92.00%	1,008	944	88.00%	769
Finance	Time Estimate	80.00%	3,050	3,150	80.00%	2,486
Purchasing	Time Estimate	90.00%	138	146	90.00%	135
Legal	Time Estimate	30.00%	96	96	30.00%	52
Enersource Hydro Charges	Historical	85.00%	705	569	85.00%	674
Capital Taxes	Historical	85.00%	20	20	85.00%	15
Other Expense/Financial Income/Other Income	Historical	85.00%	371	394	85.00%	449
Total Management Fee			$ 8,243	$ 8,383		$ 7,802
	Driver (B)	2006 EDR	2006 EDR			
Enersource Hydro Mississauga:						
Corporate Goverance	Time Estimate	90.00%	282			
Executive Management and Communications	Time Estimate	90.00%	2,519			
Safety	Time Estimate	90.00%	377			
Human Resources	Headcount	88.00%	480			
Finance	Time Estimate	80.00%	2,449			
Purchasing	Time Estimate	90.00%	120			
Legal	Estimated	33.00%	127			
Enersource Hydro Charges	Estimated	90.00%	616			
Capital Taxes	Estimated	90.00%	23			
Other Expense/Financial Income/Other Income	Estimated	90.00%	500			
Management Fee Subtotal			$ 7,494			
2005 Business Unit Realignment of Enersource Hydro Mississauga:			2004 Costs			
Customer Service Admin			1,121			
Settlements			430			
Customer Accounts			3,791			
Customer Billings			343			
Information Technology Support			3,756			
Corporate Records			580			
Stores			617			
Information System Recoveries/Allocations			(418)			
Other Allocations*			(291)			
Total Management Fee			$ 17,424			

* The change in Management fees from 2002, 2003 and 2004 where they were incurred at $15.8, $17.5 and $17.4 million to the values reported above is due to the realignment in 2005 of several Business Units from Enersource Corporation to Enersource Hydro Mississauga. The units in question were determined to function for the benefit of Hydro Mississauga only, and as such were not Corporate functions.They are as listed above. The other allocations of $.291 million should not have been allocated to Enersource Hydro affilates because the costs incurred by these business units only benefited Enersource Hydro.

The fibre charges listed in Schedule 6-8 in the 2006 EDR for access to dark fibre and internet related services was paid to Enersource Telecom until May 2006 when all of the customer contracts were sold to an external party.

Enersource believes the corporate cost allocations are "an allocation of costs for corporate and miscellaneous shared services from the parent to the utility."

Each year Enersource Corporation goes through the same budgeting process as Enersource Hydro Mississauga. The costs for each business unit are forecasted, reviewed and approved by the Board of Directors. For each business unit, other than HR, management estimates the amount of time required to support each affiliate. This percentage is then applied to the actual costs incurred on a monthly basis. This approach makes it easier to understand, less time consuming and less expensive then using timesheets for labour costs and separating every invoice based how much each company benefited

from the service that was received. The time estimates that are made by Enersource's management team represents the amount of time spent on Enersource Hydro versus non-regulated issues. Enersource uses this time estimate as the basis of allocating costs to each affiliate. For example:

(i) Corporate Governance & Executive Management/Communications and Public Relations costs are the costs that Enersource Corporation incurs for its Board of Directors, Executive management team, corporate communications and public/government relations. The costs incurred by Enersource Corporation are mainly due to the size of EHM (as compared to the non-regulated activities) and the regulations and governing bodies that EHM must follow or report to.

The management team then estimates how much each affiliate should be charged by factoring in:

- **Amount of time spent on issues**
- **Complexity of issues**
- **Size of transactions**
- **Overall materiality**
- **Communication requirements**

The amount of costs incurred by Enersource Corporation is then budgeted to be allocated based on the factors listed above. Management estimated that Hydro causes 90% of the corporate costs to be incurred while the non-regulated affiliates' cause 10% of the costs to be incurred. Enersource believes the time estimate is the most appropriate way to allocate costs.

(ii) Safety costs are the costs that Enersource Corporation incurs mainly to comply with regulatory requirements and employee safety programs.

The management team then estimates how much each affiliate should be charged by factoring in:

- **Regulatory compliance requirements by each affiliate**
- **Staffing levels**
- **Program size**
- **Type of activities performed**

The amount of costs incurred by Enersource Corporation is then budgeted to be allocated based on the factors listed above. Management estimated that Hydro causes 90% of the corporate costs to be incurred while the non-regulated affiliates' cause 10% of the costs to be incurred. Enersource believes the time estimate is the most appropriate way to allocate costs.

(iii) Finance costs are the costs that Enersource Corporation incurs mainly to comply with regulatory requirements as well as accounting and reporting standards.

The management team then estimates how much each affiliate should be charged by factoring in:

- **Regulatory and financial requirements required by each affiliate**

- **Size of transactions**
- **Complexity of transactions**
- **Number of transactions**
- **Time spent analysing and recording transactions**
- **Type of activities performed**
- **Overall materiality**
- **Etc.**

The amount of costs incurred by Enersource Corporation is then budgeted to be allocated based on the factors listed above. Management estimated that Hydro causes 80% of the corporate costs to be incurred while the non-regulated affiliates' cause 20% of the costs to be incurred. Enersource believes the time estimate is the most appropriate way to allocate costs.

(iv) Purchasing costs are the costs that Enersource Corporation incurs mainly to support procuring goods and services for use by Enersource Hydro and its affiliates.

The management team then estimates how much each affiliate should be charged by factoring in:

- **Number of purchases**
- **Complexity of purchases**
- **Time spent of issuing requests**
- **Number of suppliers**
- **Overall materiality**

The amount of costs incurred by Enersource Corporation is then budgeted to be allocated based on the factors listed above. Management estimated that Hydro causes 90% of the corporate costs to be incurred while the non-regulated affiliates' cause 10% of the costs to be incurred. Enersource believes the time estimate is the most appropriate way to allocate costs.

(v) Legal costs are the costs that Enersource Corporation incurs mainly for in-house legal support and advice. External legal costs are charged based on actual company incurring the expense.

The management team then estimates how much each affiliate should be charged by factoring in:

- **Amount of time spent on issues**
- **Complexity of issues**

The amount of costs incurred by Enersource Corporation is then budgeted to be allocated based on the factors listed above. Management estimated that Hydro causes 30% of the corporate costs to be incurred while the non-regulated affiliates' cause 70% of the costs to be incurred. Enersource believes the time estimate is the most appropriate way to allocate costs.

(vi) Enersource Hydro costs, Capital taxes and Other Expenses/Income are costs that are incurred by Enersource Corporation for IT support, Facilities, Taxes etc.

The management team then estimates how much each affiliate should be charged by factoring in:

- **Historical allocation %**
- **Overall materiality**

The amount of costs incurred by Enersource Corporation is then budgeted to be allocated based on the factors listed above. Management estimated that Hydro causes 85% of the corporate costs to be incurred while the non-regulated affiliates' cause 15% of the costs to be incurred. Enersource believes the allocation of these costs should not change significantly year over year.

Board Staff Technical Conference Question # 8

Reference: Compliance with EDR 2006 Decision

The Board's Decision and Order relating to Enersource's rate application for rates effective May 1, 2006 (RP-2005-0020/EB-2005-0360) stated, in part, where affiliate transactions were concerned that "The Applicant has presented its information clearly and has been helpful in its responses to interrogatories, but the record is still not at a satisfactory level. In future, further information will be required concerning the costs for services provided by the parent company via the Management Fee, and how these costs relate to other costs shown elsewhere in the Application, for example in Schedules 6-4, 6-5 and 6-6."

Schedules 6-4, 6-5 and 6-6 were respectively "Employee Compensation," "Employee Incentive Plan Expense," and "OMERS Pension Expense and Post-Retirement Benefits."

It would be helpful if Enersource would discuss the information it is providing in this proceeding in the context of this aspect of the Board's Decision and whether or not Enersource believes that it would need to provide any additional information to meet this requirement and, if so, how Enersource intends to provide it and, if not, why Enersource believes the information it has filed in this proceeding meets the requirements stated by the Board.

Response: 8.

Enersource is unable to provide a written response due to limited time and resources.

Board Staff Technical Conference Question # 9

Reference: Affiliate transactions

It would be helpful if Enersource could use the Technical Conference to provide an overall road map through its affiliate transactions to demonstrate that the costs are prudent, summarizing the overall amounts and magnitude relative to the total utility costs of costs incurred through shared services, as well as the cost justification for EHM going the shared services route versus in-house or third party provision of such services.

Response: 9.

Enersource is unable to provide a written response due to limited time and resources.

Board Staff Technical Conference Question # 10

Reference: Board Staff Interrogatory No. 27 - Employee Compensation

This interrogatory asked Enersource to provide a breakdown of the number of employees, salaries and wages, benefits and incentives charged to O&M by employee type for 2006 Board Approved, 2006 historical, 2007 bridge and 2008 test years. However, the response does not include information on employee benefits and incentives charged to O&M. The purpose was to determine whether the overall level of employee costs is appropriate.

(a) Please provide a breakdown of employee benefits by employee type from 2006 to 2008.

(b) With respect to the Information on Incentive Program table, please provide a comparison of total incentive amounts by employee type from 2006 to 2008.

Response: 10. a)

Refer to: Exhibit D, Schedule 1, Tab 11, Page 4 of 6, paragraph 2

For the bridge year and for the 2008 Test Year, Enersource relies on the benefits rate computed for the 2006 historical year:

- Outside hourly employee benefit rates will be applied to wages at a rate of 53%
- Inside salaried employee benefit rates will be applied to wages at a rate of 31%
- Non-Union employees benefit rates will be applied to wages at a rate of 27%

These rates represent a blended average rate for the entire year due to varying levels of benefit costs in the year (e.g. CPP and EI). The amount of benefits included under each employee category would be based on the benefit rates listed above.

Benefits are accrued on all manpower costs, and actuals go against clearing account.

Below are the benefits pertaining to above employee type:

Outside	**Inside**	**Non-Union**
AD&D [OT]	AD&D [IN]	AD&D [NU]
Bereavement [OT]	EHC & Dental [IN]	EHC & Dental [NU]
EHC & Dental [OT]	Canada Pension Plan [IN]	Canada Pension Plan [NU]
Boot Allowance [OT]	Employer Health Tax [IN]	Employer Health Tax [NU]
Canada Pension Plan [OT]	Life Insurance [IN]	Life Insurance [NU]
Employer Health Tax [OT]	LTD Premiums [IN]	LTD Premiums [NU]

Illness - STD [OT] Life Insurance [OT] LTD Premiums [OT] Meals [OT] Meals-Winter [OT] OMERS [OT] Public Holidays [OT] Safety Meetings [OT] Safety Mtgs Qtrly [OT] EI [OT] Vacation [OT] WSIB [OT] Retiree Bridge Benefit	OMERS [IN] EI [IN] WSIB [IN] Retiree Bridge Benefit Bereavement [OT] Illness - STD [OT] Public Holidays [OT] Vacation	Meals-Winter [NU] OMERS [NU] EI [NU] WSIB [NU] Directors Vehicles [NU] Retiree Bridge Benefit Bereavement [OT] Illness - STD [OT] Public Holidays [OT] Vacation

Response: 10. b)

Every employee is entitled to the same incentive pay rate. The rates were as follows: 2006 - 4.5%, 2007 - 4% and 2008 - 5% of gross. Note: Percentages are based on Non Financial measures. Financial incentives are self funding. The incentive amount is included under other expenses.

Board Staff Technical Conference Question # 11

Reference: Board Staff Interrogatory No. 27 - Employee Compensation

Based on the utility's response to IR #27, please provide the following

(a) Please confirm that total salaries and wages for non union employees is forecast to increase from $3,417,000 in 2006 to $4,162,000 in 2008, and that expressed on a "per FTE" basis the average salary increases from approximately $57,000 in 2006 to approximately $66,000 in 2008.

(b) In light of (a), please provide a justification for this two-year increase of 16%.

(c) Please confirm that total salaries and wages for analyst employees is forecast to increase from $1,540,000 in 2006 to $1,876,000 in 2008, and that expressed on a "per FTE" basis the average salary increases from approximately $59,000 in 2006 to approximately $67,000 in 2008.

(d) In light of (c), please provide a justification for this two-year increase of 13%.

(e) Please confirm that total salaries and wages for management is forecast to increase from $2,012,000 in 2006 to $2,451,000 in 2008, and that expressed on a "per FTE" basis the average salary increases from approximately $69,000 in 2006 to approximately $79,000 in 2008.

(f) In light of (e), please provide a justification for this two-year increase of 14%.

(g) Please confirm that total salaries and wages for outside employees is forecast to increase from $5,429,000 in 2006 to $6,849,000 in 2008, and that expressed on a "per FTE" basis the average salary increases from approximately $48,000 in 2006 to approximately $55,000 in 2008.

(h) In light of (g), please provide a justification for this two-year increase of 16%.

(i) Please confirm that total salaries and wages for inside employees is forecast to increase from $3,773,000 in 2006 to $4,880,000 in 2008, and that expressed on a "per FTE" basis the average salary increases from approximately $59,000 in 2006 to approximately $68,000 in 2008.

(j) In light of (i), please provide a justification for this two-year increase of 15%

(k) Please provide the rationale and justification for the increase from 64 to 72 inside positions, from 2006 to 2008.

Response: 11. a)

The OM&A costs from 2006 to 2008 "per FTE" increased from $57,000 to approximately $66,000 in 2008.

Response: 11. b)

The increase in average OM&A "per FTE" is the result of many factors.

- **The type of employee and level of employee**
- **The amount of wages charged to capital or recovery projects**
- **Salary increases and job level adjustments**
- **Number of additional staff and nature of role.**

Response: 11. c)

The OM&A costs from 2006 to 2008 "per FTE" increased from $59,000 to approximately $67,000 in 2008.

Response: 11. d)

The increase in average OM&A "per FTE" is the result of many factors.

- **The type of employee and level of employee**
- **The amount of wages charged to capital or recovery projects**
- **Salary increases and job level adjustments**
- **Number of additional staff and nature of role.**

Response: 11. e)

The OM&A costs from 2006 to 2008 "per FTE" increased from $69,000 to approximately $79,000 in 2008.

Response: 11. f)

The increase in average OM&A "per FTE" is the result of many factors.

- **The type of employee and level of employee**
- **The amount of wages charged to capital or recovery projects**
- **Salary increases and job level adjustments**
- **Number of additional staff and nature of role.**

Response: 11. g)

The OM&A costs from 2006 to 2008 "per FTE" increased from $48,000 to approximately $55,000 in 2008.

Response: 11. h)

The increase in average OM&A "per FTE" is the result of many factors.

- **The type of employee and level of employee**
- **The amount of wages charged to capital or recovery projects**
- **Salary increases and job level adjustments**
- **Number of additional staff and nature of role.**

Response: 11. i)

The OM&A costs from 2006 to 2008 "per FTE" increased from $59,000 to approximately $68,000 in 2008.

Response: 11. j)

The increase in average OM&A "per FTE" is the result of many factors.

- **The type of employee and level of employee**
- **The amount of wages charged to capital or recovery projects**
- **Salary increases and job level adjustments**
- **Number of additional staff and nature of role.**

Response: 11. k)

The increase in positions was explained in Board Staff Interrogatory #31.

Board Staff Technical Conference Question # 12

Reference: Ref: Exhibit D / Schedule 2 / Tab 6

Page 1 provides a variance analysis of Enersource's OM&A costs for 2006 and 2007. Please explain the line item "One-time Pension and Benefit repayment" and provide the rationale and justification for the variance of 2.5%.

Response: 12.

Enersource deferred its OMERS operating expenses from January to April 2006. Enersource also had a one-time overpayment reduction in life insurance benefits in 2006. Neither cost saving nor cost deferral will occur in 2007 or 2008.

Board Staff Technical Conference Question # 13

Reference: Ref: Exhibit J Schedule A Page 50, Schedule of 2006-2007 Manpower Controllable Costs, Board Staff Interrogatory No. 31

The table below has been prepared by Board Staff from Enersources IR response, Schedule of Manpower Controllable Expenses. The New Hires column is from the consolidation of Staffing Changes and reason and uses Enersources $65k per new hire. Some rounding occurs but is immaterial to this question

Name	2006 Actual	Salary Increases	Standby	Safety Training	Substation Maintenance	New Hires	Other Variance	2007 Forecast
CONTROL SYSTEM	1307	39				65	-189	1,222
CORPORATE RECORDS	540	16				65	101	722
GROUNDS & BUILDINGS	178	5					40	223
SUBSTATION OPERATIONS	572	79	80		160	65	63	1,019
SYSTEM PLANNING	200	6				65	16	287
TROUBLE TRUCK	64	2					12	78
CABLE LOCATES	530	16					49	595
U/G MAINT, REPAIRS & BURNOFFS	1649	49				65	-3	1,760
O/H MAINTENANCE & REPAIRS	1063	82				65	58	1,268
TREE TRIMMING	511	15					32	558
GARAGE	576	17					-37	556
OVERHEAD CONSTRUCTION	478	14					59	551
IND/COM'L CUST PROJ/INSPECTIONS	774	23				65	-179	683
STORES	395	12				65	-60	412
Operations	8,837	375	80	0	160	520	-39	9,934
CUSTOMER SERVICES ADMIN	1565	47				65	-22	1,655
SETTLEMENTS	586	18					58	662
CUSTOMER ACCOUNTS	2911	134				65	360	3,470
CUSTOMER BILLINGS	522	16					-45	493
METERING	548	56				65	31	700
Customer Service	6,132	271	0	0	0	195	382	6,980
Admin	3260	163		175			301	3,899
IT Support	2454	98				65	74	2,691
Manpower re-class adjustment	0	0					0	0
Other	5,714	261	0	175	0	65	375	6,590
Total OM&A	20,683	907	80	175	160	780	718	23,504

a. Please provide further details on Sub Station Operations - Standby $80 k
b. Please provide further details on Sub Station Operations - Substation Maintenance $160 k
c. Please provide further details on Admin – Safety Training - $175k

d. Enersource states “Pension and benefits increases of $718 are based on the number of employees in each business unit/work unit. The proportionate amount for each unit is based on type and number of employees in each area.” This being the case then the column identified as other variance will be impacted by the allocations. Please provide explanations for other variance that are greater than plus or minus $50k after Pension and benefits increases adjustment.

Response: 13. a)

The $80 k standby charge increases was to cover of yearly weekend shifts to ensure adequate 24 hour coverage.

Response: 13. b)

The $160 K is for the cost of a contractor to perform all grounds and maintenance at our 70 substation sites. This maintenance includes: cutting grass, trimming, picking up debris, weed control, soil sterilization and fertilizing. Previously, Enersource used students to perform this work, which was not done at satisfactorily level.

Response: 13. c)

In 2006 Enersource Corporation began holding a safety boot camp for Enersource Hydro Mississauga. The actual costs were moved to Hydro in 2007. The boot camp covers the following:

1. **Electrical Utilities Safety Rules Review**
2. **Arc Flash Risk Assessment**
3. **Work Area Protection**
4. **Session Ergonomics**
5. **Propane Safety Awareness**
6. **Safe Work Procedures**
7. **C.P.R. & A.E.D. Refresher**
8. **Workers Rights & Responsibilities**
9. **Work Protection Code Refresher**
10. **Hazard Identification**
11. **Grounding & Bonding**
12. **Generators & Standby Devices**
13. **High Voltage Potential Indicators**

Response: 13. d)

d. The $718 is from deferring OMERS operating expenses from January to April 2006. Enersource also had a one-time overpayment reduction in life insurance benefits in 2006. The additional columns that have been added (New Hires and Other Variances) can not be used. The average of $65 per employee was used to ensure confidentiality of actual salaries. The $718 is based on total OMERS operating expenses and life premiums paid on behave of Enersource employees.

Board Staff Technical Conference Question # 14

Reference: Ref: Exhibit J Schedule A Page 50, Schedule of 2006-2007 Manpower Controllable Costs

The table below has been prepared by Board Staff. Some rounding occurs but is immaterial to this question. Enersource has identified salary increases in the amount of $909k. On a departmental basis 3% appears to be the normal base used. However some departments are showing increases in excess of 3%. For each department that has an increase in excess of 3% please provide further details on reason for difference.

Name	2006 Actual	Salary Increases	% Change	2007 Forecast
CONTROL SYSTEM	1307	39	3.0%	1,222
CORPORATE RECORDS	540	16	3.0%	722
GROUNDS & BUILDINGS	178	5	2.8%	223
SUBSTATION OPERATIONS	572	79	13.8%	1,019
SYSTEM PLANNING	200	6	3.0%	287
TROUBLE TRUCK	64	2	3.1%	78
CABLE LOCATES	530	16	3.0%	595
U/G MAINT, REPAIRS & BURNOFFS	1649	49	3.0%	1,760
O/H MAINTENANCE & REPAIRS	1063	82	7.7%	1,268
TREE TRIMMING	511	15	2.9%	558
GARAGE	576	17	3.0%	556
OVERHEAD CONSTRUCTION	478	14	2.9%	551
IND/COM'L CUST PROJ/INSPECTIONS	774	23	3.0%	683
STORES	395	12	3.0%	412
Operations	8,837	375	4.2%	9,934
CUSTOMER SERVICES ADMIN	1565	47	3.0%	1,655
SETTLEMENTS	586	18	3.1%	662
CUSTOMER ACCOUNTS	2911	134	4.6%	3,470
CUSTOMER BILLINGS	522	16	3.1%	493
METERING	548	56	10.2%	700
Customer Service	6,132	271	4.4%	6,980
Admin	3260	163	5.0%	3,899
IT Support	2454	98	4.0%	2,691
Manpower re-class adjustment	0	0	0.0%	0
Other	5,714	261	4.6%	6,590
Total OM&A	20,683	907	4.4%	23,504

Response: 14.

Enersource has salary increases of 3% on average. In order to ensure the salaries paid to staff are competitive, Enersource uses and outside Human Resource consulting firm to establish the market rate of each position. If certain job functions are expanded or responsibilities increased, the job may be reevaluated and the salaries are increased to match the market rate for that job function. Increases in salary costs greater than 3% are a result of market rate adjustments.

Board Staff Technical Conference Question # 15

Reference: Ref: Exhibit J Schedule A Page 51, Schedule of 2006-2007 Manpower Controllable Costs

The table below has been prepared by Board Staff. Some rounding occurs but is immaterial to this question. Enersource has identified salary increases in the amount of $1,053k. On a departmental basis 3.5% appears to be the normal base used. However some departments are showing increases in excess of 3.5%.

Name	2007 Forecast	Salary Increases	% Change	2008 Budget
CONTROL SYSTEM	1,222	63	5.2%	1,375
CORPORATE RECORDS	722	42	5.8%	839
GROUNDS & BUILDINGS	223	7	3.1%	224
SUBSTATION OPERATIONS	1,019	39	3.8%	1,067
SYSTEM PLANNING	287	22	7.7%	366
TROUBLE TRUCK	78	2	2.6%	77
CABLE LOCATES	595	21	3.5%	613
U/G MAINT, REPAIRS & BURNOFFS	1,760	62	3.5%	1,812
O/H MAINTENANCE & REPAIRS	1,268	42	3.3%	1,289
TREE TRIMMING	558	18	3.2%	563
GARAGE	556	24	4.3%	596
OVERHEAD CONSTRUCTION	551	21	3.8%	579
IND/COM'L CUST PROJ/INSPECTIONS	683	24	3.5%	703
STORES	412	27	6.6%	498
Operations	9,934	414	4.2%	10,601
CUSTOMER SERVICES ADMIN	1,655	87	5.3%	1,814
SETTLEMENTS	662	24	3.6%	687
CUSTOMER ACCOUNTS	3,470	115	3.3%	3,593
CUSTOMER BILLINGS	493	19	3.9%	517
METERING	700	38	5.4%	795
Customer Service	6,980	283	4.1%	7,406
Admin	3,899	151	3.9%	4,097
IT Support	2,691	204	7.6%	3,081
Manpower re-class adjustment	0	0	0.0%	325
Other	6,590	355	5.4%	7,503
Total OM&A	23,504	1,052	4.5%	25,510

a. For each department that has an increase in excess of 3.5% please provide further details on reason for difference.
b. Please provide explanation for Manpower re-class adjustment of $325 k from 2008 Other Controllable Expenses.

Response: 15. a-b)

a) **Enersource has salary increases of 3% on average. In order to ensure the salaries paid to staff are competitive, Enersource uses and outside Human Resource consulting firm to establish the market rate of each position. If certain job functions are expanded or responsibilities increased, the job may be reevaluated and the salaries are increased to match the market rate for that job function. Increases in salary costs greater than 3% are a result of market rate adjustments.**

	Test
Operating Expenses:	**2008**
Controllable Costs:	
Manpower	25,510
Materials	2,006
Transportation	1,121
Other	7,572
Subtotal Controllable Costs	36,209

b) **The manpower re-class was done in order to correctly reflect the change in business unit costs. Exhibit D/Schedule 2/Tab 1 should have been:**

Board Staff Technical Conference Question # 16

Reference: Ref: Exhibit J Schedule A Page 54 to 55, Schedule of 2006-2008 Other Controllable Expenses

The table below has been prepared by Board Staff from Enersources IR response, Schedule of Other Controllable Expenses. Some rounding occurs but is immaterial to this question

Name	2006 Actual	Variance	2007 Forecast	Variance	2008 Budget
CONTROL SYSTEM	380	47	427	12	439
CORPORATE RECORDS	45	25	70	-1	69
GROUNDS & BUILDINGS	1329	184	1,513	159	1,672
SUBSTATION OPERATIONS	647	74	721	22	743
SYSTEM PLANNING	0	2	2	0	2
TROUBLE TRUCK	0	0	0	0	0
CABLE LOCATES	4	0	4	0	4
U/G MAINT, REPAIRS & BURNOFFS	1	0	1	0	1
O/H MAINTENANCE & REPAIRS	26	149	175	0	175
TREE TRIMMING	1	-1	0	0	0
GARAGE	251	30	281	9	290
OVERHEAD CONSTRUCTION	104	3	107	5	112
IND/COM'L CUST PROJ/INSPECTIONS	31	-3	28	4	32
STORES	176	55	231	41	272
Operations	2,995	565	3,560	251	3,811
CUSTOMER SERVICES ADMIN	34	5	39	0	39
SETTLEMENTS	34	203	237	0	237
CUSTOMER ACCOUNTS	864	261	1,125	36	1,161
CUSTOMER BILLINGS	0	0	0	0	0
METERING	75	20	95	0	95
Customer Service	1,007	489	1,496	36	1,532
Admin	226	14	240	122	362
IT Support	1433	555	1988	204	2192
Manpower re-class adjustment					-325
Other	1659	569	2228	326	2229
Total OM&A	5,661	1,623	7,284	613	7,572

(a) From the Schedule of Controllable Expenses table immediately above Enersource shows Stores cost increasing by $55k between 2006 and 2007and $41 k between 2007 and 2008. What is the reason for this increase?

(b) From the Schedule of Controllable Expenses table immediately above Enersource shows Settlement cost increasing by $203k between 2006 and 2007. What is the reason for this increase?

(c) From the Schedule of Controllable Expenses table immediately above Enersource shows Admin cost increasing by $204k between 2007 and 2008. What is the reason for this increase?

Response: 16. a-c)

(a) The increase between 2006 and 2007 is mainly due to increased waste and chemical disposal costs. The increase between 2007 and 2008 is due mainly from increased ESA requirements.

(b) The increase in Settlement costs is due increased manpower costs from new hires.

(c) The increase in $204 is for IT support costs. The cost increases are mainly due to increase software and hardware maintenance costs.

Board Staff Technical Conference Question # 17

Reference: Ref: Exhibit J Schedule A Page 54 to 55, Schedule of 2006-2008 Other Controllable Expenses

The table below has been prepared by Board Staff from Enersources IR response, description of drivers. Some rounding occurs but is immaterial to this question

Other Controllable Expenses - Drivers	2007	2008
Opening Expenditures	5,660	7,284
Garage - Vehicle Maintenance Costs	137	
Admin - Communication costs	14	
IT - Communication costs	171	
Substation - Equipment Repair	74	
O/H Maintenance - Equipment Repair	74	
Grounds & Buildings - Property Taxes and Maintenanc	87	33
Grounds & Buildings - Heat And Hydro	69	83
Grounds & Buildings - Waste		41
Customer Accounts - Bill Delivery and Postage	261	
IT - Software/Hardware Maintenance & Licenses	252	170
Electrical Repairs		- 38
Unexplained Drivers	485	- 1
Closing Expenditures	7,284	7,572

(a) From the drivers table immediately above Enersource shows Garage Vehicle Maintenance cost increasing by $137k between 2006 and 2007. However the Schedule of Controllable Expenses show Garage going up by $30 k. Please explain the reasons for the difference?

(b) From the drivers table immediately above Enersource shows IT Communication cost increasing by $171k between 2006 and 2007. What are the reasons for this increase?

(c) From the drivers table immediately above Enersource shows Grounds & Buildings Property Taxes and Maintenance cost increasing by $87k between 2006 and 2007and $33 k between 2007 and 2008. What are the reasons for this increase?

(d) From the drivers table immediately above Enersource shows Grounds & Buildings Heat and Hydro cost increasing by $69k between 2006 and 2007and $83 k between 2007 and 2008. What are the reasons for this increase?

(e) From the drivers table immediately above Enersource shows Customer Accounts cost increasing by $261k between 2006 and 2007. What are the reasons for this increase?

Response: 17. a-e)

(a) The increase of $137k should have been divided between Garage $28 (increased vehicle repaired costs) and $109k in O/H Maintenance & Repairs due to increased Insulator Washing costs.

(b) The increase in communications costs in IT is the results of Meter Service Provider Communication Fees. The fees are paid for the settlements department.

(c) The building at 3240 Mavis Road is an aging and requires substantial maintenance to function efficiently. Property taxes were increased between 2007 and 2008 to account for the adjacent land purchase.

(d) Heat and Hydro cost increases are mainly due to increases in energy prices and consumption.

(e) The $261k increase in customer accounts is mainly due increased postage costs and bill delivery expenses. These costs increases are from increased customer communications and increased bill delivery charges.

Board Staff Technical Conference Question # 18

Reference: Ref: Board Staff Interrogatory No. 34, Management Fees and Recoveries

The table below has been prepared by Board Staff from Enersources IR response, Management Fees and Recoveries. Some rounding occurs but is immaterial to this question

Description	2006 EDR	Variance	2006	Variance	2007	Variance	2008
Recoveries	-7,042	-1,098	-8,140	-34	-8,174	689	-7,485
		15.6%		0.4%		-8.4%	
Management Fees	7,494	308	7,802	582	8,384	-141	8,243
		4.1%		7.5%		-1.7%	
Total	452	-790	-338	548	210	548	758
		-174.8%		-162.1%		261.0%	

(a) Please provide specifics of the "economic increases" that generated the $582k or 7.5% increase in management fees from 2006 to 2007.

Response: 18. a)

The general economic increases from 2006 to 2007 are mainly the net result of increased manpower costs of approximately 3% and a one-time employee settlement that was not budgeted.

SMART METERS

Board Staff Technical Conference Question # 19

Reference: Board Staff Interrogatory No. 41 – Smart Meters

a. What will be the value of stranded meter costs at December 31, 2007 and 2008?
b. Are the stranded meter costs contained in the fixed asset meter accounts, and therefore, in rate base?
c. Over how many years does Enersource expect to recover the stranded meter costs through depreciation and return on rate base?
d. How will Enersource treat the proceeds received from salvage or recycling value of the stranded meters in its financial statements and in its tax returns for 2007? What are the proceeds and approximately how much per meter is received?
e. Please complete the table below and provide detail explanations where required.

Smart Meter Stranded Costs	**Balance Dec. 31, 2007**	**Change in 2008**	**Balance Dec. 31, 2008**
Number of meters replaced by type Residential GS<50kW Other			
Value of stranded meters by type Residential GS<50kW Other			

NBV of each type of meter, or class of meter Residential GS<50kW Other			
Revenue requirement impact of stranded meters in Test Year Return (assumptions made and calculations: ROE% debt rate %, PILs income tax rate %) Amortization PILs (dollars and income tax rate used) Any other costs (please explain) Total			

Response: 19.

a) See Chart below.
b) Yes. As indicated by The Ontario Energy Board's Decision with Reasons EB-2007-0063 on August 8, 2007 "…Many of the utilities suggested that at the present time, the stranded costs associated with existing meters should stay in rate base. The Board accepts this proposition."
c) EHM is looking for guidance from the OEB on this matter.
d) EHM will treat the proceeds received from salvage of the stranded meters by including a reduction in expenses in its financial statements and as a reduction to the disposal value of meters in its tax returns for 2007. EHM receives 19.5 cents per pound where the estimated weight of each meter is 3.75 pounds. The proceeds for 2007 are estimated at $43,875.
e) See Chart below.

Smart Meter Stranded Costs	Balance Dec. 31, 2007	Change in 2008	Balance Dec. 31, 2008
Number of Meters Replaced by Type			
Residential	60,000	35,333	95,333
GS<50kW		5,297	5,297
Other			
Value of stranded meters by type			
Residential	$1,860,000		$1,095,323
GS<50kW			$2,690,876
Other			
NBV of each type of meter, or class of meter*			
Residential	$3,064,192		$1,968,869
GS<50kW			
Other	$10,379,591		$7,688,715
Revenue requirement impact of stranded meters in Test Year	N/A		357,000
Return (assumptions made and calculations: ROE%, debt rate %, PILs income tax rate %)	N/A		280,000
Amortization	N/A		
PILs (dollars and income tax rate used)	N/A		77,000
Any other costs (please explain)	N/A		
Total	N/A		357,000

* EHM uses pooled asset classes for meters. NBV are approximations based on EHM's Reponses to Undertakings during the Smart Meter Hearing EB-2007-0063.

CONSERVATION AND DEMAND MANAGEMENT

Board Staff Technical Conference Question # 20

Reference: Board Staff Interrogatory No. 49 – CDM

Enersource has provided spreadsheets for the LRAM and SSM calculations. Please revise the spreadsheets to include a column indicating the free rider rate that was used for each CDM program.

Response: 20.

Please refer to attached updated spreadsheets with free rider rates for each program.

Note that the residential load control initiative (peak saver thermostat) is viewed as a utility controlled relay, for which the free rider rate is 0%.

The CI&I demand response programs (load control initiative and stand-by generator) also have a free rider rate of 0% since these customers would not have participated in the program without Enersource's direct involvement.

Since Enersource has not claimed all the lost revenue for the Smart Meter Commercial program based on preliminary measurements of energy savings, a free rider rate is not applicable. To be more specific, our preliminary estimate shows savings of 17.7% over a 6 month period, while Enersource is claiming only 10% at this time, pending verification of energy savings over a longer timeframe. Any free riders are easily accounted for in this differential.

ENERSOURCE - LRAM CALCULATIONS

Based on Cumulative CDM Savings as of April 30, 2007

Referenced to OEB Filing Requirements for Transmission and Distribution Applications - EB-2006-0170 November 14, 2006

Board #49

Net kWh and kW Impacts (Freeriders not included)

		Energy			Summer On-Peak Demand			Distribution Volumetric Rate (Energy Based)			Distribution Volumetric Rate (Demand Based)			LRAM			
Time Periods Referenced to Applicable Distribution Rates	**Free Rider Rate**	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	May 1, 2005 Apr 30, 2007	May 1, 2006 Oct 31, 2007	Nov 1, 2006 Apr 30, 2008	**Total** (All Periods)
Funding Mechanism, CDM Program & Customer Rate Class		(kWh)	(kWh)	(kWh)	(kW)	(kW)	(kW)	($/kWh)	($/kWh)	($/kWh)	($/kW)	($/kW)	($/kW)	($)	($)	($)	($)
3rd Tranche of MARR																	
Residential and Small Commercial																	
Residential								0.0103	0.0120	0.0121							
Co-Branded Mass Market	10.5%	1,416,460	7,956,951	8,972,375	575									$ 14,590	$ 95,483	$ 108,566	$ 218,639
SMART Meter Pilot	n/a	0			0									$ -	$ -	$ -	$ -
Residential Load Control	0.0%			1,526,728			909							$ -	$ -	$ 18,473	$ 18,473
SMART (Electric) Avenue	10.0%			4,262			32							$ -	$ -	$ 52	$ 52
Sub-Totals		1,416,460	7,956,951	10,503,366	575	0	941	0	0	0	0	0	0	$ 14,590	$ 95,483	$ 127,091	$ 237,164
GS <50								0.0136	0.0146	0.0148							
Social Housing	10.0%	46,171	96,362	224,509	3	9	15							$ 628	$ 1,407	$ 3,323	$ 5,358
Leveraging Energy Conservation (BIP)	10.0%	0		12,687			3							$ -	$ -	$ 188	$ 188
On-the-Bill (Financing) Payment Plan	10.0%	28,618			8									$ 389	$ -	$ -	$ 389
Sub-Totals		74,789	96,362	237,197	11	9	17							$ 1,017	$ 1,407	$ 3,511	$ 5,935
Commercial, Industrial & Institutional																	
GS 50~499 kW											4.0296	4.3249	4.3715				
SMART Meter Commercial	n/a	573,958				25								$ -	$ 108	$ -	$ 108
Leveraging Energy Conservation (BIP)	10.0%	0	81,877	3,262	0	25	45							$ -	$ 106	$ 197	$ 303
Load Control Initiative (DR)	0.0%						235							$ -	$ -	$ -	$ -
On-the-Bill (Financing) Payment Plan	10.0%	418,715			60									$ 240	$ -	$ -	$ 240
Sub-Totals		992,673	81,877	3,262	60	50	45							$ 240	$ 214	$ 197	$ 651
GS 500~4999 kW											1.5267	1.6657	1.6835				
SMART Meter Commercial	n/a													$ -	$ -	$ -	$ -
Leveraging Energy Conservation (BIP)	10.0%	20,615	123,688	1,439,702	14	14	172							$ 22	$ 24	$ 290	$ 335
Load Control Initiative (DR)	0.0%						2,350							$ -	$ -	$ -	$ -
On-the-Bill (Financing) Payment Plan	n/a													$ -	$ -	$ -	$ -
Sub-Totals		20,615	123,688	1,439,702	14	14	172							$ 22	$ 24	$ 290	$ 335
Large Users >5000 kW											2.5109	2.7524	2.7819				
Load Control Initiative (DR)	0.0%						2,500							$ -	$ -	$ -	$ -
Distribution Loss Reduction																	
Voltage Profile Management	n/a													$ -	$ -	$ -	$ -
Distributed Energy																	
Stand-by Generators (DR)	0.0%						*6,205*										
50~499 kW							105							$ -	$ -	$ -	$ -
500~4999 kW							4,100							$ -	$ -	$ -	$ -
>5000 kW							2,000							$ -	$ -	$ -	$ -
Incremental Funding Approved in Rates (2nd Generation)																	
Residential Sector Program																	
Residential								0.0103	0.0120	0.0121							
Water Heater Tune-ups	10.0%		473,105	3,710,144		22	171							$ -	$ 5,677	$ 44,893	$ 50,570
Seasonal LED Exchange	5.0%			103,700			0							$ -	$ -	$ 1,255	$ 1,255
CFL Bulb Drop	10.0%		392,675	2,588,073		0	0							$ -	$ 4,712	$ 31,316	$ 36,028
Sub-Totals		0	865,780	6,401,917	0	22	171							$ -	$ 10,389	$ 77,463	$ 87,853
GRAND TOTALS by Rate Class																	
Residential		1,416,460	8,822,731	16,905,283	575	22	1,111							$ 14,590	$ 105,873	$ 204,554	$ 325,016
Small Commercial GS<50 kW		74,789	96,362	237,197	11	9	17							$ 1,017	$ 1,407	$ 3,511	$ 5,935
CI&I 50~499 kW		992,673	81,877	3,262	60	50	150							$ 240	$ 214	$ 197	$ 651
500~4999 kW		20,615	123,688	1,439,702	14	14	4,272							$ 22	$ 24	$ 290	$ 335
>5000 kW		0	0	0	0	0	4,500							$ -	$ -	$ -	$ -
LRAM Grand Totals:		**2,504,537**	**9,124,657**	**18,585,443**	**660**	**95**	**10,051**							**$ 15,868**	**$ 107,518**	**$ 208,551**	**$ 331,937**

ENERSOURCE - SSM CALCULATIONS

Based on Cumulative CDM Savings as of April 30, 2007

Referenced to OEB Filing Requirements for Transmission and Distribution Applications - EB-2006-0170, November 14, 2006

Board #49

Net Savings (Freeriders not included)

		Energy (Annualized Savings)			Energy (Cumulative Totals)		Summer On-Peak Demand			SSM (Net of PILs and Freeriders)				
Time Periods Referenced to Applicable Distribution Rates	**Free Rider Rate**	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	Annual	Lifecycle	May 1, 2005 Apr 30, 2006	May 1, 2006 Oct 31, 2006	Nov 1, 2006 Apr 30, 2007	**CDM Spending**	**TRC Benefit**	**TRC Cost**	**TRC Net Benefit**	**SSM** (@ 5% of Net Benefit)
Funding Mechanism, CDM Program & Customer Rate Class		(kWh)	(kWh)	(kWh)	(kWh)	(kWh)	(kW)	(kW)	(kW)	($)	($)	($)	($)	($)
3rd Tranche of MARR														
Residential and Small Commercial (<50														
Residential														
Co-Branded Mass Market	10.5%	4,543,448	11,235,722	1,200,169	16,979,339	117,122,260	578			$ 846,393	$ 6,993,621	$ 1,138,920	$ 5,854,701	$ 292,735
SMART Meter Pilot	n/a	0			0		0			$ 251,215	$ -	$ -	$ -	$ -
Residential Load Control	0.0%			2,173,084	2,173,084	39,115,505			909	$ 705,111	$ 3,405,505	$ 1,684,749	$ 1,720,756	$ 86,038
SMART (Electric) Avenue	10.0%			9,471	9,471	94,710			35	$ 223,088	$ 23,456	$ 338,621	$ (315,165)	$ (15,758)
Sub-Totals		***4,543,448***	***11,235,722***	***3,382,724***	***19,161,893***	***156,332,475***	***578***	***0***	***944***	***$ 2,025,807***	***$ 10,422,582***	***$ 3,162,290***	***$ 7,260,292***	***$ 363,015***
GS <50 kW														
Social Housing	10.0%	47,306	183,010	141,639	371,956	3,196,445	3	10	16	$ 120,465	$ 259,238	$ 207,870	$ 51,367	$ 2,568
Leveraging Energy Conservation (BIP)	10.0%	0		23,380	23,380	147,903			4	$ 1,123	$ 9,469	$ 4,843	$ 4,626	$ 231
On-the-Bill (Financing) Payment Plan	10.0%			37,535	37,535	187,677	4		7	$ 6,846	$ 14,814	$ 15,237	$ (423)	$ (21)
Sub-Totals		***47,306***	***183,010***	***202,555***	***432,871***	***3,532,025***	***8***	***10***	***27***	***$ 128,434***	***$ 283,521***	***$ 227,950***	***$ 55,570***	***$ 2,779***
Commercial, Industrial & Institutional (>50														
GS 50~499 kW														
SMART Meter Commercial	n/a		459,532		459,532	6,892,979		30		$ 246,995	$ -	$ -	$ -	$ -
Leveraging Energy Conservation (BIP)	10.0%	0	256,120	6,011	262,131	1,658,255	0	75	76	$ 12,586	$ 106,166	$ 54,297	$ 51,869	$ 2,593
Load Control Initiative (DR)	0.0%				0	0			235	$ 13,959	$ 214,806	$ 75,128	$ 139,678	$ 6,984
On-the-Bill (Financing) Payment Plan	10.0%			549,186	549,186	2,745,932	36		56	$ 100,167	$ 216,741	$ 222,937	$ (6,196)	$ (310)
Sub-Totals		***0***	***715,652***	***555,198***	***1,270,849***	***11,297,165***	***36***	***105***	***132***	***$ 373,706***	***$ 537,712***	***$ 352,361***	***$ 185,351***	***$ 9,268***
GS 500~4999 kW														
SMART Meter Commercial	n/a				0	0				$ -	$ -	$ -	$ -	$ -
Leveraging Energy Conservation (BIP)	10.0%	227,933	227,933	5,058,397	5,514,263	34,883,528	24	24	553	$ 264,758	$ 2,233,340	$ 1,142,198	$ 1,091,141	$ 54,557
Load Control Initiative (DR)	0.0%				0	0			2,350	$ 139,585	$ 2,148,059	$ 751,278	$ 1,396,781	$ 69,839
On-the-Bill (Financing) Payment Plan	n/a				0	0				$ -	$ -	$ -	$ -	$ -
Sub-Totals		***227,933***	***227,933***	***5,058,397***	***5,514,263***	***34,883,528***	***24***	***24***	***553***	***$ 404,343***	***$ 4,381,398***	***$ 1,893,476***	***$ 2,487,922***	***$ 124,396***
Large Users >5000 kW														
Load Control Initiative (DR)	0.0%				0	0			2,500	$ 148,495	$ 2,285,169	$ 799,232	$ 1,485,937	$ 74,297
Distribution Loss Reduction														
Voltage Profile Management[1)]	n/a				0	0				$ 627,929	$ -	$ -	$ -	NA
Distributed Energy														
Load Displacement	n/a													
GS <50 kW					0	0				$ 34,654	$ -	$ 34,654	$ (34,654)	$ (1,733)
GS 50~499 kW					0	0				$ 34,654	$ -	$ 34,654	$ (34,654)	$ (1,733)
Sub-Totals					***0***	***0***				***$ 69,307***	***$ -***	***$ 69,307***	***$ (69,307)***	***$ (3,465)***
Stand-by Generators (DR)	0.0%													
GS 50~499 kW					0	0			105	$ 25,070	$ 95,977	$ 38,369	$ 57,608	$ 2,880
GS 500~4999 kW					0	0			4,100	$ 978,937	$ 3,747,677	$ 1,498,237	$ 2,249,440	$ 112,472
Large Users >5000 kW					0	0			2,000	$ 477,530	$ 1,828,135	$ 730,847	$ 1,097,288	$ 54,864
Sub-Totals					***0***	***0***			***6,205***	***$ 1,481,537***	***$ 5,671,789***	***$ 2,267,454***	***$ 3,404,335***	***$ 170,217***
Overall Program Support														
Special Events Van *(totalized under Co-Branded Mass Markets)*					0	0							$ -	$ -
Program Support - Regulatory Reporting, Other					0	0				***$ 1,360,201***		***$ 1,360,201***	$ (1,360,201)	$ (68,010)
Sub-Totals					***0***	***0***							***$ -***	***$ -***
3rd Tranche of MARR Portfolio Totals		***4,818,687***	***12,362,317***	***9,198,873***	***26,379,877***	***206,045,192***	***646***	***139***	***4,156***	***6,619,759***	***23,582,171***	***10,132,271***	***$ 13,449,900***	***$ 672,495***
Note: 1) Voltage Profile Management Program is not a customer focussed initiative and therefore it does not qualify for SSM claims.														
Incremental Funding Approved in Rates (2nd Generation)														
Residential Sector Program														
Residential														
Water Heater Tune-ups	10.0%		1,547,870	3,082,819	4,630,689	36,448,797		72	140	$ 480,334	$ 3,009,201	$ 480,334	$ 2,528,868	$ 126,443
Seasonal LED Exchange	5.0%			103,700	103,700	3,111,003			0	$ 112,711	$ 143,220	$ 113,837	$ 29,383	$ 1,469
CFL Bulb Drop	10.0%		1,353,667	1,457,315	2,810,983	12,087,228		0	0	$ 252,202	$ 721,058	$ 252,202	$ 468,856	$ 23,443
Sub-Totals		***0***	***2,901,537***	***4,643,834***	***7,545,372***	***51,647,028***	***0***	***72***	***140***	***$ 845,247***	***$ 3,873,480***	***$ 846,373***	***$ 3,027,107***	***$ 151,355***
Incremental Funding (2nd Gen.) Totals		***0***	***2,901,537***	***4,643,834***	***7,545,372***	***51,647,028***	***0***	***72***	***140***	***845,247***	***3,873,480***	***846,373***	***$ 3,027,107***	***$ 151,355***
CDM Portfolio-Based Totals by Rate Class														
Incremental Funding - **Residential**		0	2,901,537	4,643,834	7,545,372	51,647,028	0	72	140	$ 845,247	$ 3,873,480	$ 846,373	$ 3,027,107	$ 151,355
3rd Tranche - **Residential**		4,543,448	11,235,722	3,382,724	19,161,893	156,332,475	578	0	944	$ 2,025,807	$ 10,422,582	$ 3,162,290	$ 7,260,292	$ 363,015
Small Commercial GS<50 kW		47,306	183,010	202,555	432,871	3,532,025	8	10	27	$ 163,087	$ 283,521	$ 262,604	$ 20,917	$ 1,046
CI&I 50~499 kW		0	715,652	555,198	1,270,849	11,297,165	36	105	237	$ 433,430	$ 633,690	$ 425,384	$ 208,306	$ 10,415
500~4999 kW		227,933	227,933	5,058,397	5,514,263	34,883,528	24	24	4,653	$ 1,383,280	$ 8,129,075	$ 3,391,713	$ 4,737,361	$ 236,868
>5000 kW		0	0	0	0	0	0	0	4,500	$ 626,025	$ 4,113,304	$ 1,530,079	$ 2,583,224	$ 129,161
Program Support - Regulatory Reporting, Other		0	0	0	0	0	0	0	0	1,360,201	0	1,360,201	$ (1,360,201)	$ (68,010)
CDM Portfolio-Based SSM Totals		**4,818,687**	**15,263,854**	**13,842,707**	**33,925,249**	**257,692,220**	**646**	**210**	**10,501**	**$ 6,837,077**	**$ 27,455,651**	**$ 10,978,645**	**$ 16,477,007**	**$ 823,850**

Board Staff Technical Conference Question # 21

Reference: Board Staff Interrogatory No. 50 & VECC Interrogatory No. 19 – CDM

In the response to Board staff question #50, Enersource stated that "some adopted measures (e.g. 13 W CFLs) were not included in the TRC Table, but we followed the TRC Guide prescribed methodology in confirming savings". However, in the response to VECC question #19, Enersource stated that "all Enersources programs related to mass market and are the subject of the Board's Total Resource Cost Guide. Enersource did not offer any custom programs and as a result has not relied on data from a source other than the Board's Total Resource Cost Guide".

a. These statements appear contradictory. Please confirm which specific programs did not rely on data from the TRC Guide. For each of these programs, please provide the inputs and assumptions that were used, and documentation supporting these inputs and assumptions.

b. Enersource has stated that it did not offer any custom programs. However, in the Toronto Hydro Decision EB-2007-0096, the Board determined that Toronto Hydro's Load Displacement Program should have a custom project free rider rate of 30%. Please confirm what free rider rate Enersource is using for the Load Displacement Program. If Enersource did not use a free rider rate of 30%, please provide Enersource's rationale for using a different free rider rate.

Response: 21. a-b)

(a) The two statements are not contradictory. The 13W-CFLs are not in the TRC Guide specifically, so Enersource followed the same methodology used in the Guide for the 15W-CFLs to arrive at the annual kWh savings for a 13W-CFL. In other words, the 15W-CFL was used as a proxy for the 13W-CFL in the calculation of annual energy savings. We also used same ratios for kWh distribution across the specified eight time periods per year, same annual operating time, life expectancy and freeridership rate. Note that both 13W and 15W CFLs are meant to replace a 60W incandescent bulb because they give out similar lumens, comparable to those generated by a 60W incandescent. A similar proxy methodology was used in the Social Housing Program, for the 23W-CFLs distributed (not listed in the OEB Measures List), using the same operating parameters listed for the 25W-CFLs. 23W-CFLs can be utilized interchangeably with 25W-CFLs, to replace 100W incandescent bulbs.

(b) Although Enersource has costs associated with the Load Displacement program, there are currently no benefits to claim. The freeridership rate is applicable in the calculation of lifecycle benefits; that is, energy savings due to avoided consumption over the life of the measure. To date, there are no energy savings associated with this program.

LOSS FACTORS

Board Staff Technical Conference Question # 22

Reference: Board Staff Interrogatory No. 48

Response to Board Staff Interrogatory No. 48 (a) (i) indicates that Enersource's DLF for 2002 to 2006 is provided on the line titled "Loss Factor" in the 1st reference.

a. Please answer the balance of the question by providing values for the corresponding TLF for 2002 to 2006 and the Supply Facilities Loss Factor (SFLF) used to convert DLF to TLF.

b. Please confirm that the title "Total Loss factor" of the table in the 1st reference is incorrect and should be replaced by "Distribution Loss Factor".

Response: 22. a)

a) **Enersource proposes to continue to rely on a Supply Facilities Loss Factor of 1.0045. Enersource notes that the Board's Decision and Order RP-2005-0020/EB-2005-0360 authorized "Loss Factors" and that the supporting worksheet in EDR 2006 model is titled "Loss Factors" and, in particular neither authorizes nor references "Total Loss Factor", "Distribution Loss Factor" or "Supply Facilities Loss Factor". These terms are not used in the Board's 2006 EDR Report of the Board or in the Board's 2006 Rates Handbook. They are used by Hydro One in its 2006 EDR evidence.**

The associated Total Loss Factors, computed using Hydro One's methodology, are provided in table 1 below.

Table 1 - TLF, SFLF and DLF 2002 - 2006

	2002	2003	2004	2005	2006
Calculated DLF	1.0454	1.0352	1.0353	1.0331	1.0424
SFLF	1.0045	1.0045	1.0045	1.0045	1.0045
Calculated TLF	1.0501	1.0399	1.0400	1.0377	1.0471

Response: 22. b)

b) **Enersource proposes that Exhibit D/ Schedule 2/ Tab 9.2 be titled "Loss Factors".**

Board Staff Technical Conference Question # 23

Reference: Board Staff Interrogatory No. 48

Response to Board Staff Interrogatory No. 48 (a) (ii)"Enersource relied on the 2006 EDR methodology" does not answer the question which seeks an explanation for the calculation method used in the table in the 1st reference to obtain Loss Factor (confirmed as DLF in the response to the previous question).

a. If the intent of the response is to imply that the calculation method follows the framework of the 2006 EDR Handbook Schedule 10-5, the intent is unfulfilled as the table in the 1st reference is not a proper representation of Schedule 10-5.

b. Please provide details of the calculation used to obtain the DLF value, for example by showing data for each year 2002 – 2006 in the framework of the 2006 EDR Handbook Schedule 10-5. This comprises rows A thru H, where row G (row C/row F) represents the DLF calculation.

Response: 23. a-b)

a) Enersource provides the requested proper representation of Schedule 10-5, EDR 2006 below.

Calculation of Distribution Loss Factor

		2002	2003	2004	2005	2006
a	Wholesale kWh	7893199846	7835477880	7935629620	8274861000	8038675830
b	Wholesale kWh for Large Users	961594638	1021022787	1014805301	990465178.9	989866464.1
c	Net Wholesale kWh	6931605208	6814455094	6920824319	7284395821	7048809366
d	Retail kWh	7582464082	7593570208	7689582883	8031718000	7741962941
e	Retail kWh for Large Users	952073899	1010913650	1004757724	980658593	980065806
f	Net Retail kWh	6630390183	6582656558	6684825159	7051059407	6761897135
g	Loss factor	1.045429457	1.035213524	1.035303715	1.033092391	1.04243073
h				1.038648899	1.034536543	1.036942278

b) Please see the response to part a) above.

Board Staff Technical Conference Question # 24

Reference: Board Staff Interrogatory No. 48

Response to Board Staff Interrogatory No. 48 (a) (iii) "Please refer to Exhibit D/Schedule 1/Tab 5"does not answer the question which seeks an explanation for the 2006 increase in the DLF. The table in the 1st reference shows the DLF increasing from 3.31% in 2005 to 4.24% in 2006.

a. Please provide an explanation for this increase.
b. The reference (Exhibit D/Schedule 1/Tab 5) provided in the response refers to Bad Debts and is unrelated to the subject of loss factors. Please confirm if this refence is incorrect.
c. The 3rd reference contains a statement "A summary of Enersource's distribution system loss factors for 2002-2006 is provided in ExD/Sched2/Tab9". However distribution loss factors are provided in ExD/Sched1/Tab9.2 (1st reference). Please explain this discrepancy.

Response: 24. a-c)

a) **Please refer to Exhibit D/ Schedule 1/ Tab 5 where Enersource references the write-off of amounts related to a billing error related to a large customer. The subject billing error was rooted in a meter error. Upon the discovery of that specific meter error Enersource reviewed its metering installations for all customers with demand greater than 200 kW. This review identified other meter errors that have since been corrected. Because these meter errors occurred in 2006 Enersource's metered kWh in 2006 are lower than they ought to be and consequently its loss factor was higher than it ought to be.**

b) **Please see the response to part a) above.**

c) **Please note that Exhibit D/ Schedule 2/ Tab 9 provides two supporting schedules. Tab 9.1 provides information on Enersource's observed technical losses, derived using an in-house model, and Tab 9.2 provides information on Enersource's computed loss factor, derived using the Board's schedule 10-5 of the 2006 EDR.**

Board Staff Technical Conference Question # 25

Reference: Board Staff Interrogatory No. 48

Response to Board Staff Interrogatory No. 48 (b) "Enersource has not proposed any change to the TLF – Secondary Metered Customer >5,000 kW or to the TLF – Primary Metered Customer >5,000 kW"does not answer the question which seeks to know which of the four TLFs for 2008 (Primary and Secondary customers < and > 5,000 kW) provided in both the 2nd and 3rd references corresponds to the DLF provided in the 1st reference.

a. Please confirm if the "Average of 3 year averages" DLF of 3.7% shown in the 1st reference is proposed for 2008.
b. If the above is true, please confirm if this DLF (3.7%) is the basis for the TLF of 3.6% (1.0360) for Secondary Metered Customer < 5,000 kW shown in both the 2nd and 3rd references.
c. If the above is true, please explain why the TLF (3.6%) is lower than the DLF (3.7%) as the TLF comprises DLF plus losses incurred in system supply facilities (captured by SFLF).

Response: 25. a-c)

a) **The proposed loss factors referenced at Exhibit H/ Schedule 4/ Tab 1/p.2 are derived from the loss factor calculated at Exhibit D/Schedule 2/ Tab 9.2. Knowing that the kWh data for 2006 results in an overstatement of the 2006 loss factor it was considered appropriate to reduce the proposed 2008 loss factors. The proposed loss factors reflect an adjustment based on the observed technical losses of 3%, as determined using the in-house model, and an assumed ongoing, typical level of non-technical losses of 0.6%.**

b) **Enersource has provided the calculated Total Loss Factor in its response to OEB Staff question 23 a). The calculated 2006 Total Loss Factor is less than the proposed 2008 Distribution Loss Factor due to the data concerns discussed in the response to part a). Please note that 3.7% is the computed average of 3 year rolling average loss factors.**

c) **Please see the response to part b) above.**

Board Staff Technical Conference Question # 26

Reference: Board Staff Interrogatory No. 48

Please explain the correlation between the calculations shown in the table "Enersource's Loss Factors per Loss Model" in the 4th reference and the DLF calculations shown in the 1st reference.

Response: 26.

The technical Distribution Loss Factor components provided at Exhibit D/ Schedule 2 / Tab 9.1 are comparable between years and move consistently under both modeled load factors. They are considered reasonable estimates of the incurred technical losses of approximately 3.1%. This level of technical loss was applied to the computed Distribution Losses, as set out at Tab 9.2, to estimate the range of non-technical losses incurred in 2002 – 2006, being 0.2% - 1.5%. Enersource has relied on a typical level of non-technical losses of approximately 0.5% to determine the proposed Total Loss Factor of 3.6%.

As discussed in the response to Board staff question 22 the 2006 EDR Model, Board Report and Rate Handbook did not make reference to the term Supply Facilities Load Factor.

COST ALLOCATION & RATE DESIGN

Board Staff Technical Conference Question # 27

Reference: Board Staff Interrogatory No. 61

Further to Board Staff Interrogatory No. 61, please provide the following:

f. Does Run 1 or Run 2 of the Informational Filing (EB-2006-0247) more closely represent the customer classification in the Application? Please file it as an official part of the record of this Application.

g. Using data from Sheet O1 'Revenue to Cost Summary Worksheet', please calculate as a percentage for each class the 'Revenue Requirement (includes NI)' compared to the total revenue requirement.

h. Reference: Exhibit H / Schedule 2 / Tab 1: Please substitute the percentage calculated in part b into the eighth column (headed "Percentage"), and complete the rest of the table with these percentages.

Response: 27.

a) **Consistent with the Board's requirements, Enersource's existing customer classes are relied on for the purposes of Run 1 of the Cost Allocation Review – Informational Filing and is attached.**

b) **Please note that this calculation is provided at Exhibit H/ Schedule 2/ Tab 1; please see the attached worksheet.**

c) **No changes are required to the referenced evidence.**

Ontario Energy Board

2006 COST ALLOCATION INFORMATION FILING

Sheet I1 Utility Information Sheet

Name of LDC:	Enersource Hydro Mississauga		
License Number:	ED-2003-0017		
EDR 2006 EB Number:	EB-2005-0360	**Cost Allocation EB Number:**	EB-2006-0247 ⟸ drop-down menu
Date of Submission:	Monday, January 15, 2007	**Version:**	1.2
Contact Information Name:	Kathi Litt		
Title:	Manager, Rates & Regulatory		
Phone Number:	905-283-4247		
E-Mail Address:	klitt@enersource.com		

****Please Note: Colour Coding Legend ****

Input Cells	
Output Cells	
Exhibition	
Brought Forward	Brought Forward
Calculation	Calculation
Default Numbers	
Diagnostic	

Brief Description of Each Worksheet's Function

INPUTS	I1	Intro	Brief explanation of what the pages do.
	I2	LDC data and Classes	Enter LDC specific information and number of classes etc
	I3	TB Data	Balance from approved 2006 EDR Trial Balance
	I4	BO ASSETS	Break out assets into detail functions - bulk deliver, primary and secondary
	I5	Misc Data	Input for miscellaneous data where necessary - TBD
	I6	Customer Data	Input customer related data for generating customer allocators
	I7.1	Meter Capital	Input meter related data for calculating capital costs weighing factors
	I7.2	Meter Reading	Input meter related data for calculating meter reading weighing factors
	I8	Demand Data	Input demand allocators using load data and making LDC specific adjustments
	I9	Direct Allocation	
OUTPUTS	O1	Revenue to cost	Output showing revenue to cost ratios, inter class subsidy etc.
	O2	Fixed Charge	Output showing the range for the Basic Customer charge - TBD
	O2.1	Line Transformer PLCC Adjustment	
	O2.2	Primary Cost PLCC Adjustment	
	O2.3	Secondary Cost PLCC Adjustment	
	O3.1	Line Tran Unit Cost	
	O3.2	Substat Tran Unit Cost	
	O3.3	Primary Cost Pool	
	O3.4	Secondary Cost Pool	
	O3.5	USL Metering Credit	
	O4	Summary by Class	Output showing summary of all allocation by class and by US of A
	O5	Detail by Class	Output showing details of individual allocation by class and by USofA
	O6	Source Data for E2	
	O7	Amortization	
EXHIBITS	E1	Categorization	Exhibit showing how costs are categorized
	E2	Allocation Factors	Exhibit summarizing all allocation factors created in I5 to I8 and present the findings in percentages
	E3	PLCC	Backup documentation for calculating Peak Load Carrying Capability.
	E4	Trial Balance Index	Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated
	E5	Reconciliation	Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance

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2006 COST ALLOCATION INFORMATION FILING
Enersource Hydro Mississauga
EB-2005-0360 EB-2006-0247
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Sheet I2 Class Selection - First Run

Instructions:
Step 1: Please input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

Click for Drop-Down Menu → First Run

If desired, provide a summary of this run (40 characters max.)

		Utility's Class Definition	Current
1	Residential	Residential	YES
2	GS <50	Small Commercial	YES
3	GS>50-Regular	GS < 50kW	YES
4	GS> 50-TOU	GS 50 - 499kW	YES
5	GS >50-Intermediate	GS 500 - 4999kW	YES
6	Large Use >5MW	Large User > 5MW	YES
7	Street Light	Street Light	YES
8	Sentinel		NO
9	Unmetered Scattered Load		NO
10	Embedded Distributor		NO
11	Back-up/Standby Power		NO
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

Update

Grouped Accounts as per 2006 EDR	Financial Statement (EDR Sheet 2.4, Column P	Reclassified Balance
Land and Buildings	$17,216,086	$17,216,086
TS Primary Above 50	$0	$0
DS	$59,278,829	$59,680,534
Poles, Wires	$488,408,032	$465,150,507
Line Transformers	$69,807,172	$69,807,172
Services and Meters	$31,195,923	$54,051,744
General Plant	$0	$0
Equipment	$17,041,054	$17,041,054
IT Assets	$9,299,784	$9,299,784
CDM Expenditures and Recoveries	$2,792,500	$2,792,500
Other Distribution Assets	$14,401,351	$14,401,351
Contributions and Grants	($42,229,794)	($46,106,522)
Accumulated Amortization	($278,087,924)	($274,211,196)
Non-Distribution Asset	($1,024,000)	($1,024,000)
Unclassified Asset	$10,111,023	$10,111,023
Liability	$0	$0
Equity	$0	($17,096,816)
Sales of Electricity	($539,669,159)	($539,669,159)
Distribution Services Revenue	($90,819,143)	($108,786,791)
Late Payment Charges	($404,246)	($404,246)
Specific Service Charges	($2,009,032)	($1,123,271)
Other Distribution Revenue	($283,198)	($283,198)
Other Revenue - Unclassified	$0	$0
Other Income & Deductions	($2,056,959)	($2,056,959)
Power Supply Expenses (Working Capital)	$539,290,714	$539,290,714
Other Power Supply Expenses	$0	$0
Operation (Working Capital)	$11,077,429	$12,704,359
Maintenance (Working Capital)	$2,048,004	$2,273,447
Billing and Collection (Working Capital)	($151,449)	($151,449)
Community Relations (Working Capital)	$0	$0
Community Relations - CDM (Working Capital)	$1,525,000	$1,525,000
Administrative and General Expenses (Working Capital)	$16,364,507	$15,774,439
Insurance Expense (Working Capital)	$799,851	$799,851
Bad Debt Expense (Working Capital)	$958,885	$958,885
Advertising Expenses	$0	$0
Charitable Contributions	$10,757	$10,757
Amortization of Assets	$29,965,918	$29,965,918
Other Amortization - Unclassified	$0	$0
Interest Expense - Unclassified	$0	$18,350,583
Income Tax Expense - Unclassified	$1,469,413	$13,345,859
Other Distribution Expenses	$0	$0
Non-Distribution Expenses	$0	$0
Unclassified Expenses	$0	$0
Total	$366,327,328	$363,637,958

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Enersource Hydro Mississauga

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Sheet I5 Miscellaneous Data Worksheet - First Run

kMs of Roads in Service Area Where Distribution Lines Exist	2366
Deemed Equity Component of Rate Base (%)	40%

	1	2	3	4	5	6	7
	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
Instructions (Cont'd): Step 3: Insert Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column W)	11.31	14.29	28.84	72.96	1234.56	13190.7	0.36
Step 4: Insert Smart Meter Adder Included in Approved Monthly Service Charge (Please refer to Approved EDR Sheet 8-5 column T)	0.31	0.31	0.31	0.31	0.31	0.31	

2006 COST ALLOCATION INFORMATION FILING

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Sheet I6 Customer Data Worksheet - First Run

Total kWhs	7,705,766,449
Total kWs	13,265,897
Total Approved Distribution Revenue ($)	$108,766,791

			1	2	3	4	5	6	7
	ID	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
Billing Data									
kWh from approved EDR model, Sheet 7-1, Col M	CEN	7,705,766,449	1,561,994,785	18,167,666	718,236,573	2,547,801,269	1,906,101,495	914,693,972	38,770,689
kW from approved EDR model, Sheet 7-1, Col S	CDEM	13,265,897				6,598,847	5,010,621	1,548,240	108,190
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		4,630,933				459,258	2,537,925	1,633,750	-
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
kWh excluding KWh from Wholesale Market Participants	CEN EWMP	7,705,766,449	1,561,994,785	18,167,666	718,236,573	2,547,801,269	1,906,101,495	914,693,972	38,770,689
kWh - 30 year weather normalized amount		7,679,331,158	1,497,316,375	12,779,045	654,627,580	2,290,045,998	2,203,813,631	984,497,230	36,251,300
Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	$108,786,791	$39,242,149	$993,556	$15,982,624	$32,049,473	$14,343,434	$5,678,206	$497,351
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$1,047,209	$458,099	$0	$208,164	$165,633	$215,313	$0	$0
Late Payment 3 Year Historical Average	LPHA	$493,364	$202,695	$240	$95,836	$136,098	$57,027	$1,468	$0
Weighting Factor - Services			1.0	2.0	10.0	10.0	10.0	30.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	7.0	7.0	15.0	1.0
Number of Bills	CNB	1,226,700	983,983	4,115	185,942	47,438	5,106	104	12
Number of Connections (Unmetered)	CCON	13,398		3,158					10,240
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	175,316	154,721	425	15,848	3,903	409	9	1
Bulk Customer Base	CCB	-	-	-	-	-	-	-	-
Primary Customer Base	CCP	175,316	154,721	425	15,848	3,903	409	9	1
Line Transformer Customer Base	CCLT	174,875	154,721	425	15,724	3,746	259	-	-
Secondary Customer Base	CCS	174,875	154,721	425	15,724	3,746	259	-	-
Weighted - Services	CWCS	368,567	154,721	6,316	157,240	37,460	2,590	-	10,240
Weighted Meter - Capital	CWMC	24,712,060	8,253,960	17,625	7,835,165	7,489,810	1,064,900	50,600	-
Weighted Meter Reading	CWMR	1,336,350	944,112	1,404	116,382	101,004	159,924	12,936	588
Weighted Bills	CWNB	2,663,187	983,983	8,230	1,301,594	332,066	35,742	1,560	12
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		104,850,629	37,617,227	698,862	14,567,159	28,807,100	16,583,721	6,111,528	465,032

Weather Normalized Data from Hydro

	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
kWh - 30 year weather normalized amount	7,983,492,677	1,562,150,174	13,332,378	682,972,954	2,389,204,989	2,299,238,761	998,772,440	37,820,981
2006 EDR Distribution Loss Factor		1.0433	1.0433	1.0433	1.0433	1.0433	1.0145	1.0433

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	594,718	293,846		142,070	78,213	80,589		
Sheet ADJ5 rows 26 - 32, column F	1,216,371	562,987		302,174	213,203	138,007		
Sheet ADJ5 rows 26 - 32, column G	1,330,538	517,462		180,248	205,483	427,344		
Three-year average	1,047,209	458,099	-	208,164	165,633	215,313	-	-

2006 COST ALLOCATION
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Sheet I7.1 Meter Capital Worksheet - First Run

Meter Types	Cost per Meter (Installed)	Residential 1 Number of Meters	Residential 2 Weighted Metering Costs	Residential 3 Weighted Average Costs	Small Commercial 1 Number of Meters	Small Commercial 2 Weighted Metering Costs	Small Commercial 3 Weighted Average Costs
Allocation Percentage Weighted Factor				33.40%			0%
Cost Relative to Residential Average Cost				1.00			1.46
Total		154805	8253960	53.31843287	226	17625	77.98672566
Single Phase 200 Amp - Urban	50	152,586	7629300		185	9750	
Single Phase 200 Amp - Rural	150		0			0	
Central Meter	250		0			0	
Network Meter (Costs to be updated)	225	1,654	417150		19	4275	
Three-phase - No demand	210	21	4410		10	2100	
Smart Meters	300		0			0	
Demand without IT (usually three-phase)	500	1	500		1	500	
Demand with IT	2,100		0			0	
Demand with IT and Interval Capability - Secondary or Primary	2,300		0			0	
Demand with IT and Interval Capability - Primary	10,000		0			0	
Demand with IT and Interval Capability - Special (WMP)	40,000		0			0	
LDC Specific - single Phase w/IT	400	234	93600			0	
- 3 Phase w/IT No Demand	1200		0			0	
- Single phase w/Dem, w/IT	1000	109	109000		1	1000	
Memory	1400		0			0	

Meter Types	Cost per Meter (Installed)	GS < 50kW 1 Number of Meters	GS < 50kW 2 Weighted Metering Costs	GS < 50kW 3 Weighted Average Costs	GS 50 - 499kW 1 Number of Meters	GS 50 - 499kW 2 Weighted Metering Costs	GS 50 - 499kW 3 Weighted Average Costs	GS 500 - 4999kW 1 Number of Meters	GS 500 - 4999kW 2 Weighted Metering Costs	GS 500 - 4999kW 3 Weighted Average Costs
Allocation Percentage Weighted Factor				32%			30%			4%
Cost Relative to Residential Average Cost				8.27			35.96			43.14
Total		15848	7835185	494.3945608	3906	7489810	1917.514081	463	1064900	2300
Single Phase 200 Amp - Urban	50	1482	74100			0			0	
Single Phase 200 Amp - Rural	150		0			0			0	
Central Meter	250		0			0			0	
Network Meter (Costs to be updated)	225	169	38025			0			0	
Three-phase - No demand	210	9844	2067240		1	210			0	
Smart Meters	300		0			0			0	
Demand without IT (usually three-phase)	500	1,875	937500		594	297000			0	
Demand with IT	2,100	1,904	3998400		1727	3626700			0	
Demand with IT and Interval Capability - Secondary or Primary	2,300	137	315100		1531	3521300		463	1064900	
Demand with IT and Interval Capability - Primary	10,000		0			0			0	
Demand with IT and Interval Capability - Special (WMP)	40,000		0			0			0	
LDC Specific - single Phase w/IT	400	143	57200		18	7200			0	
- 3 Phase w/IT No Demand	1200	42	50400			0			0	
- Single phase w/Dem, w/IT	1000	139	139000		29	39000			0	
Memory	1400	113	158200		6	8400			0	

Meter Types	Cost per Meter (Installed)	Large User > 5MW 1 Number of Meters	Large User > 5MW 2 Weighted Metering Costs	Large User > 5MW 3 Weighted Average Costs	Street Light 1 Number of Meters	Street Light 2 Weighted Metering Costs	Street Light 3 Weighted Average Costs (2	TOTAL 1 Number of Meters	TOTAL 2 Weighted Metering Costs	TOTAL 3 Weighted Average Costs (2
Allocation Percentage Weighted Factor				0%			0%			100%
Cost Relative to Residential Average Cost				43.14			-			2.84
Total		22	50600	2300	0	0	-	175270	24712060	140.9942375
Single Phase 200 Amp - Urban	50		0			0		154,263	7713150	
Single Phase 200 Amp - Rural	150		0			0		0	0	
Central Meter	250		0			0		0	0	
Network Meter (Costs to be updated)	225		0			0		2,042	459450	
Three-phase - No demand	210		0			0		9,876	2073960	
Smart Meters	300		0			0		0	0	
Demand without IT (usually three-phase)	500		0			0		2,471	1235500	
Demand with IT	2,100		0			0		3,631	7625100	
Demand with IT and Interval Capability - Secondary or Primary	2,300	22	50600			0		2,153	4951900	
Demand with IT and Interval Capability - Primary	10,000		0			0		0	0	
Demand with IT and Interval Capability - Special (WMP)	40,000		0			0		0	0	
LDC Specific - single Phase w/IT	400		0			0		395	158000	
- 3 Phase w/IT No Demand	1200		0			0		42	50400	
- Single phase w/Dem, w/IT	1000		0			0		276	278000	
Memory	1400	0	0			0		119	156600	

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Sheet I7.2 Meter Reading Worksheet - First Run

Weighting Factors based on Contractor Pricing

Description		1			2			3			4			5			6			7					
		Residential			Small Commercial			GS < 50kW			GS 50 - 499kW			GS 500 - 4999kW			Large User > 5MW			Street Light			TOTAL		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			70.65%			0.11%			8.71%			7.56%			11.97%			0.97%			0.04%			100.00%
	Cost Relative to Residential Average Cost			1.00			1.00			1.00			2.08			28.78			49.00			49.00			131.86
	Total	944,112	944,112	1.00	1,404	1,404	1.00	116,382	116,382	1.00	48,588	101,004	2.08	5,556	159,924	28.78	264	12,936	49.00	12	588	49.00	1,116,318	1,336,350	132
	Factor																								
Residential - Urban - Outside	1.00	944,112	944,112		1,404	1,404		116,382	116,382		47,496	47,496		2,340	2,340			0			0		1,111,734	1,111,734	
Residential - Urban - Outside with other services	1.00		0			0			0			0			0			0			0		-	-	
Residential - Urban - Inside	2.00		0			0			0			0			0			0			0		-	-	
Residential - Urban - Inside - with other services	1.00		0			0			0			0			0			0			0		-	-	
Residential - Rural - Outside	3.00		0			0			0			0			0			0			0		-	-	
Residential - Rural - Outside with other services	2.00		0			0			0			0			0			0			0		-	-	
LDC Specific 1			0			0			0			0			0			0			0		-	-	
LDC Specific 2			0			0			0			0			0			0			0		-	-	
GS - Walking	2.00		0			0			0			0			0			0			0		-	-	
GS - Walking - with other services	3.00		0			0			0			0			0			0			0		-	-	
GS - Vehicle with other services — TOU Read	3.00		0			0			0			0			0			0			0		-	-	
GS - Vehicle with other services	3.00		0			0			0			0			0			0			0		-	-	
LDC Specific 3			0			0			0			0			0			0			0		-	-	
LDC Specific 4	0.00		0			0			0			0			0			0			0		-	-	
Interval	49.00		0			0			0		1,092	53,508		3,216	157,584		264	12,936		12	588		4,584	224,616	
LDC Specific 5			0			0			0			0			0			0			0		-	-	
LDC Specific 6			0			0			0			0			0			0			0		-	-	

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Sheet I8 Demand Data Worksheet - First Run

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	4	5	6	7
Customer Classes		Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	1,386,482	324,964	1,280	147,434	459,069	336,288	117,456	-
Bulk Delivery CP	BCP1	1,380,270	323,498	1,275	146,773	457,013	334,782	116,930	-
Total Sytem CP	DCP1	1,380,270	323,498	1,275	146,773	457,013	334,782	116,930	-
4 CP									
Transformation CP	TCP4	5,202,269	1,149,853	5,236	522,444	1,714,133	1,341,110	469,493	-
Bulk Delivery CP	BCP4	5,178,964	1,144,702	5,213	520,104	1,706,454	1,335,102	467,389	-
Total Sytem CP	DCP4	5,178,964	1,144,702	5,213	520,104	1,706,454	1,335,102	467,389	-
12 CP									
Transformation CP	TCP12	14,346,171	3,150,400	18,179	1,426,591	4,712,673	3,663,385	1,348,917	26,026
Bulk Delivery CP	BCP12	14,281,903	3,136,286	18,097	1,420,200	4,691,561	3,646,973	1,342,875	25,909
Total Sytem CP	DCP12	14,281,903	3,136,286	18,097	1,420,200	4,691,561	3,646,973	1,342,875	25,909
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	1,512,734	390,149	2,118	151,023	457,013	361,648	141,548	9,135
Primary NCP	PNCP1	1,505,957	388,402	2,109	150,346	454,965	360,028	141,013	9,094
Line Transformer NCP	LTNCP1	1,167,673	373,967	2,030	143,621	420,356	218,943	-	8,756
Secondary NCP	SNCP1	1,167,673	373,967	2,030	143,621	420,356	218,943	-	8,756
4 NCP									
Classification NCP from Load Data Provider	DNCP4	5,726,970	1,399,878	7,737	568,601	1,759,689	1,396,954	557,979	36,132
Primary NCP	PNCP4	5,701,314	1,393,607	7,703	566,054	1,751,806	1,390,696	555,479	35,970
Line Transformer NCP	LTNCP4	4,368,861	1,341,813	7,416	540,733	1,618,546	845,721	-	34,633
Secondary NCP	SNCP4	4,368,861	1,341,813	7,416	540,733	1,618,546	845,721	-	34,633
12 NCP									
Classification NCP from Load Data Provider	DNCP12	15,777,148	3,663,721	20,320	1,554,572	4,932,299	3,914,751	1,585,225	106,259
Primary NCP	PNCP12	15,706,469	3,647,308	20,229	1,547,607	4,910,203	3,897,213	1,578,124	105,783
Line Transformer NCP	LTNCP12	12,018,149	3,511,755	19,477	1,478,378	4,536,683	2,370,004	-	101,852
Secondary NCP	SNCP12	12,018,149	3,511,755	19,477	1,478,378	4,536,683	2,370,004	-	101,852

2006 COST ALLOCATION
Enersource Hydro Missi
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Sheet I9 Direct Allocation Worksheet - First Run

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 Small Commercial	3 GS < 50 kW	4 GS 50 - 499 kW	5 GS 500 - 4999 kW	6 Large User > 5 MW	7 Street Light
	Instructions: To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line									
1995	Contributions and Grants - Credit	$0	Yes							
	Instructions: The Following is Used to Allocate Directly Allocated Costs from I5 to Rate Classifications									
1805	Land	$0	Yes							
1806	Land Rights	$0	Yes							
1808	Buildings and Fixtures	$0	Yes							
1810	Leasehold Improvements	$0	Yes							
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes							
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes							
1825	Storage Battery Equipment	$0	Yes							
1830	Poles, Towers and Fixtures	$0	Yes							
1835	Overhead Conductors and Devices	$0	Yes							
1840	Underground Conduit	$0	Yes							
1845	Underground Conductors and Devices	$0	Yes							
1850	Line Transformers	$0	Yes							
1855	Services	$0	Yes							
1860	Meters	$0	Yes							
1905	Land	$0	Yes							
1906	Land Rights	$0	Yes							
1908	Buildings and Fixtures	$0	Yes							
1910	Leasehold Improvements	$0	Yes							
1915	Office Furniture and Equipment	$0	Yes							
1920	Computer Equipment - Hardware	$0	Yes							
1925	Computer Software	$0	Yes							
1930	Transportation Equipment	$0	Yes							
1935	Stores Equipment	$0	Yes							
1940	Tools, Shop and Garage Equipment	$0	Yes							
1945	Measurement and Testing Equipment	$0	Yes							
1950	Power Operated Equipment	$0	Yes							
1955	Communication Equipment	$0	Yes							
1960	Miscellaneous Equipment	$0	Yes							
1970	Load Management Controls - Customer Premises	$0	Yes							
1975	Load Management Controls - Utility Premises	$0	Yes							
1980	System Supervisory Equipment	$0	Yes							
1990	Other Tangible Property	$0	Yes							
2005	Property Under Capital Leases	$0	Yes							
2010	Electric Plant Purchased or Sold	$0	Yes							
2060	Completed Construction Not Classified - Electric	$0	Yes							
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	Yes							
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes							
	Directly Allocated Net Fixed Assets			$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	Yes							
5010	Load Dispatching	$0	Yes							
5012	Station Buildings and Fixtures Expense	$0	Yes							
5014	Transformer Station Equipment - Operation Labour	$0	Yes							
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes							
5016	Distribution Station Equipment - Operation Labour	$0	Yes							
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes							
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes							
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes							
5030	Overhead Subtransmission Feeders - Operation	$0	Yes							
5035	Overhead Distribution Transformers - Operation	$0	Yes							
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	Yes							
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	Yes							
5050	Underground Subtransmission Feeders - Operation	$0	Yes							
5055	Underground Distribution Transformers - Operation	$0	Yes							
5065	Meter Expense	$0	Yes							
5070	Customer Premises - Operation Labour	$0	Yes							
5075	Customer Premises - Materials and Expenses	$0	Yes							
5085	Miscellaneous Distribution Expense	$0	Yes							
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes							
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes							
5096	Other Rent	$0	Yes							
5105	Maintenance Supervision and Engineering	$0	Yes							
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes							
5112	Maintenance of Transformer Station Equipment	$0	Yes							
5114	Maintenance of Distribution Station Equipment	$0	Yes							
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes							
5125	Maintenance of Overhead Conductors and Devices	$0	Yes							
5130	Maintenance of Overhead Services	$0	Yes							
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes							
5145	Maintenance of Underground Conduit	$0	Yes							
5150	Maintenance of Underground Conductors and Devices	$0	Yes							
5155	Maintenance of Underground Services	$0	Yes							
5160	Maintenance of Line Transformers	$0	Yes							
5175	Maintenance of Meters	$0	Yes							
5305	Supervision	$0	Yes							
5310	Meter Reading Expense	$0	Yes							
5315	Customer Billing	$0	Yes							
5320	Collecting	$0	Yes							
5325	Collecting - Cash Over and Short	$0	Yes							
5330	Collection Charges	$0	Yes							
5335	Bad Debt Expense	$0	Yes							
5340	Miscellaneous Customer Accounts Expenses	$0	Yes							
5405	Supervision	$0	Yes							
5410	Community Relations - Sundry	$0	Yes							
5415	Energy Conservation	$0	Yes							
5420	Community Safety Program	$0	Yes							
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes							
5505	Supervision	$0	Yes							
5510	Demonstrating and Selling Expense	$0	Yes							
5515	Advertising Expense	$0	Yes							
5520	Miscellaneous Sales Expense	$0	Yes							
5605	Executive Salaries and Expenses	$0	Yes							
5610	Management Salaries and Expenses	$0	Yes							
5615	General Administrative Salaries and Expenses	$0	Yes							
5620	Office Supplies and Expenses	$0	Yes							
5625	Administrative Expense Transferred Credit	$0	Yes							
5630	Outside Services Employed	$0	Yes							
5635	Property Insurance	$0	Yes							
5640	Injuries and Damages	$0	Yes							
5645	Employee Pensions and Benefits	$0	Yes							
5650	Franchise Requirements	$0	Yes							
5655	Regulatory Expenses	$0	Yes							
5660	General Advertising Expenses	$0	Yes							
5665	Miscellaneous General Expenses	$0	Yes							
5670	Rent	$0	Yes							
5675	Maintenance of General Plant	$0	Yes							
5680	Electrical Safety Authority Fees	$0	Yes							
5705	Amortization Expense - Property, Plant, and Equipment	$0	Yes							
5710	Amortization of Limited Term Electric Plant	$0	Yes							
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes							
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes							
6105	Taxes Other Than Income Taxes	$0	Yes							
6205	Donations	$0	Yes							
6210	Life Insurance	$0	Yes							
6215	Penalties	$0	Yes							
6225	Other Deductions	$0	Yes							
	Total Expenses			$0	$0	$0	$0	$0	$0	$0
	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0

		Allocated	Residential	Small Commercial	GS < 50 kW	GS 50 - 499 kW	GS 500 - 4999 kW	Large User > 5 MW	Street Light
Total Net Fixed Assets Excluding Gen Plant	$864,777,306								
Approved Total PILs	$13,345,858	$0	$0	$0	$0	$0	$0	$0	$0
Approved Total Return on Debt	$18,350,586	$0	$0	$0	$0	$0	$0	$0	$0
Approved Total Return on Equity	$17,044,819	$0	$0	$0	$0	$0	$0	$0	$0

	Residential	Small Commercial	GS < 50 kW	GS 50 - 499 kW	GS 500 - 4999 kW	Large User > 5 MW	Street Light
Total	$0	$0	$0	$0	$0	$0	$0

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Sheet O1 Revenue to Cost Summary Worksheet - First Run

Class Revenue. Cost Analysis. and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light
crev	Distribution Revenue (sale)	$108,786,791	$39,242,149	$993,556	$15,982,624	$32,049,473	$14,343,434	$5,678,206	$497,351
mi	Miscellaneous Revenue (mi)	$3,867,674	$1,519,063	$16,699	$1,038,292	$790,593	$379,487	$85,335	$38,207
	Total Revenue	$112,654,466	$40,761,211	$1,010,255	$17,020,916	$32,840,065	$14,722,920	$5,763,541	$535,557
	Expenses								
di	Distribution Costs (di)	$13,556,997	$5,433,883	$89,242	$1,987,438	$3,289,360	$2,020,981	$477,615	$259,476
cu	Customer Related Costs (cu)	$2,228,245	$1,267,183	$14,675	$362,161	$314,974	$220,343	$1,061	$47,848
ad	General and Administration (ad)	$18,110,047	$7,675,630	$118,700	$2,679,921	$4,147,212	$2,579,885	$556,583	$352,115
dep	Depreciation and Amortization (dep)	$29,965,918	$12,340,428	$162,903	$3,492,221	$7,523,056	$4,698,758	$1,190,717	$557,834
INPUT	PILs (INPUT)	$13,345,859	$5,406,736	$78,869	$1,787,215	$3,268,142	$2,036,533	$540,515	$247,850
INT	Interest	$18,350,583	$7,434,273	$108,445	$2,429,924	$4,493,701	$2,800,237	$743,209	$340,795
	Total Expenses	$95,557,649	$39,558,133	$572,834	$12,718,880	$23,035,446	$14,356,738	$3,509,700	$1,805,918
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$17,096,816	$6,926,341	$101,036	$2,263,904	$4,186,678	$2,608,916	$692,431	$317,510
	Revenue Requirement (includes NI)	$112,654,465	$46,484,474	$673,870	$14,982,784	$27,222,124	$16,965,654	$4,202,131	$2,123,429
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$664,777,303	$272,032,394	$3,758,432	$82,451,699	$165,495,483	$102,674,785	$26,001,599	$12,362,911
gp	General Plant - Gross	$44,663,428	$18,270,618	$264,942	$5,770,249	$10,931,883	$6,814,397	$1,768,106	$843,233
accum dep	Accumulated Depreciation	($274,211,196)	($112,262,207)	($1,441,608)	($31,992,883)	($69,899,981)	($43,085,259)	($10,540,126)	($4,989,130)
co	Capital Contribution	($46,106,522)	($20,313,018)	($281,716)	($4,771,622)	($11,241,271)	($7,025,592)	($1,489,413)	($983,890)
	Total Net Plant	$389,123,013	$157,727,787	$2,300,049	$51,457,443	$95,286,114	$59,378,331	$15,740,164	$7,233,126
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$539,290,714	$109,316,742	$1,271,470	$50,266,033	$178,308,748	$133,399,168	$64,015,172	$2,713,380
	OM&A Expenses	$33,895,289	$14,376,696	$222,617	$5,029,520	$7,750,546	$4,821,210	$1,035,259	$659,440
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$573,186,003*	*$123,693,438*	*$1,494,087*	*$55,295,554*	*$186,059,294*	*$138,220,378*	*$65,050,431*	*$3,372,820*
	Working Capital	$85,977,900	$18,554,016	$224,113	$8,294,333	$27,908,894	$20,733,057	$9,757,565	$505,923
	Total Rate Base	$475,100,913	$176,281,803	$2,524,162	$59,751,776	$123,195,009	$80,111,387	$25,497,729	$7,739,049
		Rate Base Input equals Output							
	Equity Component of Rate Base	$190,040,365	$70,512,721	$1,009,665	$23,900,710	$49,278,003	$32,044,555	$10,199,091	$3,095,619
	Net Income on Allocated Assets	$17,096,817	$1,203,078	$437,421	$4,302,036	$9,804,620	$366,183	$2,253,840	($1,270,361)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$17,096,817	$1,203,078	$437,421	$4,302,036	$9,804,620	$366,183	$2,253,840	($1,270,361)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	87.69%	149.92%	113.60%	120.64%	86.78%	137.16%	25.22%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$1	($5,723,263)	$336,385	$2,038,132	$5,617,942	($2,242,733)	$1,561,410	($1,587,871)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	1.71%	43.32%	18.00%	19.90%	1.14%	22.10%	-41.04%

Ontario

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	4	5	6	7
Summary	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
Customer Unit Cost per month - Avoided Cost	$1.21	$0.73	$5.51	$21.74	$23.34	$59.26	$0.39
Customer Unit Cost per month - Directly Related	$1.80	$1.18	$7.15	$28.18	$32.08	$77.65	$0.84
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.67	$13.32	$33.99	$60.91	$147.23	$202.91	$12.72
Fixed Charge per approved 2006 EDR	$11.31	$14.29	$28.84	$72.96	$1,234.56	$13,190.70	$0.36

ALLOCATION BY RATE CLASSIFICATION

USoA Account #	Accounts	O1 Grouping	Total	1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light
1565	Conservation and Demand Management Expenditures and Recoveries	dp								
1608	Franchises and Consents	gp								
1805	Land	dp								
1805-1	Land Station >50 kV	dp								
1805-2	Land Station <50 kV	dp								
1806	Land Rights	dp								
1806-1	Land Rights Station >50 kV	dp								
1806-2	Land Rights Station <50 kV	dp								
1808	Buildings and Fixtures	dp								
1808-1	Buildings and Fixtures > 50 kV	dp								
1808-2	Buildings and Fixtures < 50 KV	dp								
1810	Leasehold Improvements	dp								
1810-1	Leasehold Improvements >50 kV	dp								
1810-2	Leasehold Improvements <50 kV	dp								
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp								
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	dp								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	dp								
1825	Storage Battery Equipment	dp								
1825-1	Storage Battery Equipment > 50 kV	dp								
1825-2	Storage Battery Equipment <50 kV	dp								
1830	Poles, Towers and Fixtures	dp								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	dp								
1830-4	Poles, Towers and Fixtures - Primary	dp								
1830-5	Poles, Towers and Fixtures - Secondary	dp								
1835	Overhead Conductors and Devices	dp								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	dp								
1835-4	Overhead Conductors and Devices - Primary	dp								
1835-5	Overhead Conductors and Devices - Secondary	dp								
1840	Underground Conduit	dp								
1840-3	Underground Conduit - Bulk Delivery	dp								
1840-4	Underground Conduit - Primary	dp								
1840-5	Underground Conduit - Secondary	dp								
1845	Underground Conductors and Devices	dp								
1845-3	Underground Conductors and Devices - Bulk Delivery	dp								
1845-4	Underground Conductors and Devices - Primary	dp								
1845-5	Underground Conductors and Devices - Secondary	dp								
1850	Line Transformers	dp								
1855	Services	dp								
1860	Meters	dp								
1905	Land	gp								
1906	Land Rights	gp								
1908	Buildings and Fixtures	gp								
1910	Leasehold Improvements	gp								
1915	Office Furniture and Equipment	gp								
1920	Computer Equipment - Hardware	gp								
1925	Computer Software	gp								
1930	Transportation Equipment	gp								
1935	Stores Equipment	gp								
1940	Tools, Shop and Garage Equipment	gp								
1945	Measurement and Testing Equipment	gp								

1950	Power Operated Equipment	gp
1955	Communication Equipment	gp
1960	Miscellaneous Equipment	gp
1970	Load Management Controls - Customer Premises	gp
1975	Load Management Controls - Utility Premises	gp
1980	System Supervisory Equipment	gp
1990	Other Tangible Property	gp
1995	Contributions and Grants - Credit	co
2005	Property Under Capital Leases	gp
2010	Electric Plant Purchased or Sold	gp
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	accum dep
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	accum dep
3046	Balance Transferred From Income	NI
4080	Distribution Services Revenue	CREV
4082	Retail Services Revenues	mi
4084	Service Transaction Requests (STR) Revenues	mi
4090	Electric Services Incidental to Energy Sales	mi
4205	Interdepartmental Rents	mi
4210	Rent from Electric Property	mi
4215	Other Utility Operating Income	mi
4220	Other Electric Revenues	mi
4225	Late Payment Charges	mi
4235	Miscellaneous Service Revenues	mi
4240	Provision for Rate Refunds	mi
4245	Government Assistance Directly Credited to Income	mi
4305	Regulatory Debits	mi
4310	Regulatory Credits	mi
4315	Revenues from Electric Plant Leased to Others	mi
4320	Expenses of Electric Plant Leased to Others	mi
4325	Revenues from Merchandise, Jobbing, Etc	mi
4330	Costs and Expenses of Merchandising, Jobbing, Etc	mi
4335	Profits and Losses from Financial Instrument Hedges	mi
4340	Profits and Losses from Financial Instrument Investments	mi
4345	Gains from Disposition of Future Use Utility Plant	mi
4350	Losses from Disposition of Future Use Utility Plant	mi
4355	Gain on Disposition of Utility and Other Property	mi
4360	Loss on Disposition of Utility and Other Property	mi
4365	Gains from Disposition of Allowances for Emission	mi
4370	Losses from Disposition of Allowances for Emission	mi
4390	Miscellaneous Non-Operating Income	mi
4395	Rate-Payer Benefit Including Interest	mi
4398	Foreign Exchange Gains and Losses, Including Amortization	mi
4405	Interest and Dividend Income	mi
4415	Equity in Earnings of Subsidiary Companies	mi
4705	Power Purchased	cop
4708	Charges-WMS	cop
4710	Cost of Power Adjustments	cop
4712	Charges-One-Time	cop
4714	Charges-NW	cop
4715	System Control and Load Dispatching	cop
4716	Charges-CN	cop
4730	Rural Rate Assistance Expense	cop
5005	Operation Supervision and Engineering	di
5010	Load Dispatching	di
5012	Station Buildings and Fixtures Expense	di
5014	Transformer Station Equipment - Operation Labour	di

5015	Transformer Station Equipment - Operation Supplies and Expenses	di
5016	Distribution Station Equipment - Operation Labour	di
5017	Distribution Station Equipment - Operation Supplies and Expenses	di
5020	Overhead Distribution Lines and Feeders - Operation Labour	di
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	di
5030	Overhead Subtransmission Feeders - Operation	di
5035	Overhead Distribution Transformers- Operation	di
5040	Underground Distribution Lines and Feeders - Operation Labour	di
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	di
5050	Underground Subtransmission Feeders - Operation	di
5055	Underground Distribution Transformers - Operation	di
5065	Meter Expense	cu
5070	Customer Premises - Operation Labour	cu
5075	Customer Premises - Materials and Expenses	cu
5085	Miscellaneous Distribution Expense	di
5090	Underground Distribution Lines and Feeders - Rental Paid	di
5095	Overhead Distribution Lines and Feeders - Rental Paid	di
5096	Other Rent	di
5105	Maintenance Supervision and Engineering	di
5110	Maintenance of Buildings and Fixtures - Distribution Stations	di
5112	Maintenance of Transformer Station Equipment	di
5114	Maintenance of Distribution Station Equipment	di
5120	Maintenance of Poles, Towers and Fixtures	di
5125	Maintenance of Overhead Conductors and Devices	di
5130	Maintenance of Overhead Services	di
5135	Overhead Distribution Lines and Feeders - Right of Way	di
5145	Maintenance of Underground Conduit	di
5150	Maintenance of Underground Conductors and Devices	di
5155	Maintenance of Underground Services	di
5160	Maintenance of Line Transformers	di
5175	Maintenance of Meters	cu
5305	Supervision	cu
5310	Meter Reading Expense	cu
5315	Customer Billing	cu
5320	Collecting	cu
5325	Collecting - Cash Over and Short	cu
5330	Collection Charges	cu
5335	Bad Debt Expense	cu
5340	Miscellaneous Customer Accounts Expenses	cu
5405	Supervision	ad
5410	Community Relations - Sundry	ad
5415	Energy Conservation	ad
5420	Community Safety Program	ad
5425	Miscellaneous Customer Service and Informational Expenses	ad
5505	Supervision	ad
5510	Demonstrating and Selling Expense	ad
5515	Advertising Expense	ad
5520	Miscellaneous Sales Expense	ad
5605	Executive Salaries and Expenses	ad
5610	Management Salaries and Expenses	ad
5615	General Administrative Salaries and Expenses	ad
5620	Office Supplies and Expenses	ad

5625	Administrative Expense Transferred Credit	ad								
5630	Outside Services Employed	ad								
5635	Property Insurance	ad								
5640	Injuries and Damages	ad								
5645	Employee Pensions and Benefits	ad								
5650	Franchise Requirements	ad								
5655	Regulatory Expenses	ad								
5660	General Advertising Expenses	ad								
5665	Miscellaneous General Expenses	ad								
5670	Rent	ad								
5675	Maintenance of General Plant	ad								
5680	Electrical Safety Authority Fees	ad								
5685	Independent Market Operator Fees and Penalties	cop								
5705	Amortization Expense - Property, Plant, and Equipment	dep								
5710	Amortization of Limited Term Electric Plant	dep								
5715	Amortization of Intangibles and Other Electric Plant	dep								
5720	Amortization of Electric Plant Acquisition Adjustments	dep								
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	dep								
5735	Amortization of Deferred Development Costs	dep								
5740	Amortization of Deferred Charges	dep								
6005	Interest on Long Term Debt	INT								
6105	Taxes Other Than Income Taxes	ad								
6110	Income Taxes	input								
6205	Donations	ad								
6210	Life Insurance	ad								
6215	Penalties	ad								
6225	Other Deductions	ad								
			$894,220,094	$258,915,110	$3,033,063	$95,157,536	$259,603,564	$189,802,400	$76,809,065	$10,899,356
				$894,220,094						

2006 COST ALLOCATION INFORMATION FILING

Enersource Hydro Mississauga

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Sheet O5 Details of Allocators by Class and Account Worksheet - First Run

Uniform System of Accounts - Detail Accounts

	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW
						Categorization			Allocation - Demand Related 1	2	3	4	5
19	1565	Conservation and Demand Management Expenditures and Recoveries											
20	1608	Franchises and Consents											
21	1805	Land											
22	1805-1	Land Station >50 kV											
23	1805-2	Land Station <50 kV											
24	1806	Land Rights											
25	1806-1	Land Rights Station >50 kV											
26	1806-2	Land Rights Station <50 kV											
27	1808	Buildings and Fixtures											
28	1808-1	Buildings and Fixtures > 50 kV											
29	1808-2	Buildings and Fixtures < 50 KV											
30	1810	Leasehold Improvements											
31	1810-1	Leasehold Improvements >50 kV											
32	1810-2	Leasehold Improvements <50 kV											
33	1815	Transformer Station Equipment - Normally Primary above 50 kV											
34	1820	Distribution Station Equipment - Normally Primary below 50 kV											
35	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)											
36	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)											
37	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)											
38	1825	Storage Battery Equipment											
39	1825-1	Storage Battery Equipment > 50 kV											
40	1825-2	Storage Battery Equipment <50 kV											
41	1830	Poles, Towers and Fixtures											
42	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery											
43	1830-4	Poles, Towers and Fixtures - Primary											
44	1830-5	Poles, Towers and Fixtures - Secondary											
45	1835	Overhead Conductors and Devices											
46	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery											
47	1835-4	Overhead Conductors and Devices - Primary											
48	1835-5	Overhead Conductors and Devices - Secondary											
49	1840	Underground Conduit											
50	1840-3	Underground Conduit - Bulk Delivery											
51	1840-4	Underground Conduit - Primary											
52	1840-5	Underground Conduit - Secondary											
53	1845	Underground Conductors and Devices											
54	1845-3	Underground Conductors and Devices - Bulk Delivery											
55	1845-4	Underground Conductors and Devices - Primary											
56	1845-5	Underground Conductors and Devices - Secondary											
57	1850	Line Transformers											
58	1855	Services											
59	1860	Meters											
60	1905	Land											
61	1906	Land Rights											
62	1908	Buildings and Fixtures											
63	1910	Leasehold Improvements											

	A	B	C	D	E	F	G	H	I	J	K	L	M
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW
64	1915	Office Furniture and Equipment											
65	1920	Computer Equipment - Hardware											
66	1925	Computer Software											
67	1930	Transportation Equipment											
68	1935	Stores Equipment											
69	1940	Tools, Shop and Garage Equipment											
70	1945	Measurement and Testing Equipment											
71	1950	Power Operated Equipment											
72	1955	Communication Equipment											
73	1960	Miscellaneous Equipment											
74	1970	Load Management Controls - Customer Premises											
75	1975	Load Management Controls - Utility Premises											
76	1980	System Supervisory Equipment											
77	1990	Other Tangible Property											
78	1995	Contributions and Grants - Credit											
79	2005	Property Under Capital Leases											
80	2010	Electric Plant Purchased or Sold											
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment											
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles											
83	3046	Balance Transferred From Income											
84	[redacted]												
85													
86													
87													
88													
89													

18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW
90	4215	Other Utility Operating Income											
91	4220	Other Electric Revenues											
92	4225	Late Payment Charges											
93	4235	Miscellaneous Service Revenues											
94	4240	Provision for Rate Refunds											
95	4245	Government Assistance Directly Credited to Income											
96	4305	Regulatory Debits											
97	4310	Regulatory Credits											
98	4315	Revenues from Electric Plant Leased to Others											
99	4320	Expenses of Electric Plant Leased to Others											
100	4325	Revenues from Merchandise, Jobbing, Etc.											
101	4330	Costs and Expenses of Merchandising, Jobbing, Etc.											
102	4335	Profits and Losses from Financial Instrument Hedges											
103	4340	Profits and Losses from Financial Instrument Investments											
104	4345	Gains from Disposition of Future Use Utility Plant											
105	4350	Losses from Disposition of Future Use Utility Plant											
106	4355	Gain on Disposition of Utility and Other Property											
107	4360	Loss on Disposition of Utility and Other Property											
108	4365	Gains from Disposition of Allowances for Emission											
109	4370	Losses from Disposition of Allowances for Emission											
110	4390	Miscellaneous Non-Operating Income											
111	4395	Rate-Payer Benefit Including Interest											
112	4398	Foreign Exchange Gains and Losses, Including Amortization											
113	4405	Interest and Dividend Income											
114	4415	Equity in Earnings of Subsidiary Companies											
115	4705	Power Purchased											
116	4708	Charges-WMS											
117	4710	Cost of Power Adjustments											
118	4712	Charges-One-Time											
119	4714	Charges-NW											
120	4715	System Control and Load Dispatching											
121	4716	Charges-CN											
122	4730	Rural Rate Assistance Expense											
123	5005	Operation Supervision and Engineering											
124	5010	Load Dispatching											
125	5012	Station Buildings and Fixtures Expense											
126	5014	Transformer Station Equipment - Operation Labour											
127	5015	Transformer Station Equipment - Operation Supplies and Expenses											
128	5016	Distribution Station Equipment - Operation Labour											
129	5017	Distribution Station Equipment - Operation Supplies and Expenses											
130	5020	Overhead Distribution Lines and Feeders - Operation Labour											
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses											
132	5030	Overhead Subtransmission Feeders - Operation											
133	5035	Overhead Distribution Transformers- Operation											
134	5040	Underground Distribution Lines and Feeders - Operation Labour											
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses											
136	5050	Underground Subtransmission Feeders - Operation											
137	5055	Underground Distribution Transformers - Operation											
138	5065	Meter Expense											

	A	B	C	D	E	F	G	H	I	J	K	L	M
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW
139	5070	Customer Premises - Operation Labour											
140	5075	Customer Premises - Materials and Expenses											
141	5085	Miscellaneous Distribution Expense											
142	5090	Underground Distribution Lines and Feeders - Rental Paid											
143	5095	Overhead Distribution Lines and Feeders - Rental Paid											
144	5096	Other Rent											
145	5105	Maintenance Supervision and Engineering											
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations											
147	5112	Maintenance of Transformer Station Equipment											
148	5114	Maintenance of Distribution Station Equipment											
149	5120	Maintenance of Poles, Towers and Fixtures											
150	5125	Maintenance of Overhead Conductors and Devices											
151	5130	Maintenance of Overhead Services											
152	5135	Overhead Distribution Lines and Feeders - Right of Way											
153	5145	Maintenance of Underground Conduit											
154	5150	Maintenance of Underground Conductors and Devices											
155	5155	Maintenance of Underground Services											
156	5160	Maintenance of Line Transformers											
157	5175	Maintenance of Meters											
158	5305	Supervision											
159	5310	Meter Reading Expense											
160	5315	Customer Billing											
161	5320	Collecting											
162	5325	Collecting - Cash Over and Short											
163	5330	Collection Charges											
164	5335	Bad Debt Expense											
165	5340	Miscellaneous Customer Accounts Expenses											
166	5405	Supervision											
167	5410	Community Relations - Sundry											
168	5415	Energy Conservation											
169	5420	Community Safety Program											
170	5425	Miscellaneous Customer Service and Informational Expenses											
171	5505	Supervision											
172	5510	Demonstrating and Selling Expense											
173	5515	Advertising Expense											
174	5520	Miscellaneous Sales Expense											
175	5605	Executive Salaries and Expenses											
176	5610	Management Salaries and Expenses											
177	5615	General Administrative Salaries and Expenses											
178	5620	Office Supplies and Expenses											
179	5625	Administrative Expense Transferred Credit											
180	5630	Outside Services Employed											
181	5635	Property Insurance											
182	5640	Injuries and Damages											
183	5645	Employee Pensions and Benefits											
184	5650	Franchise Requirements											
185	5655	Regulatory Expenses											
186	5660	General Advertising Expenses											
187	5665	Miscellaneous General Expenses											
188	5670	Rent											
189	5675	Maintenance of General Plant											
190	5680	Electrical Safety Authority Fees											
191	5685	Independent Market Operator Fees and Penalties											
192	5705	Amortization Expense - Property, Plant, and Equipment											
193	5710	Amortization of Limited Term Electric Plant											
194	5715	Amortization of Intangibles and Other Electric Plant											
195	5720	Amortization of Electric Plant Acquisition Adjustments											

2006 COST ALLOCATION INFORMATION FILING

Enersource Hydro Mississauga

EB-2005-0360 EB-2006-0247

Monday, January 15, 2007

Sheet O5 Details of Allocators by Class and Account Worksheet - Fir

Uniform System of Accounts - Detail Accounts

Row	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Large User > 5MW	Street Light	Total - Demand
17						Categorization	6	7	
19	1565	Conservation and Demand Management Expenditures and Recoveries							
20	1608	Franchises and Consents							
21	1805	Land							
22	1805-1	Land Station >50 kV							
23	1805-2	Land Station <50 kV							
24	1806	Land Rights							
25	1806-1	Land Rights Station >50 kV							
26	1806-2	Land Rights Station <50 kV							
27	1808	Buildings and Fixtures							
28	1808-1	Buildings and Fixtures > 50 kV							
29	1808-2	Buildings and Fixtures < 50 KV							
30	1810	Leasehold Improvements							
31	1810-1	Leasehold Improvements >50 kV							
32	1810-2	Leasehold Improvements <50 kV							
33	1815	Transformer Station Equipment - Normally Primary above 50 kV							
34	1820	Distribution Station Equipment - Normally Primary below 50 kV							
35	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)							
36	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)							
37	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)							
38	1825	Storage Battery Equipment							
39	1825-1	Storage Battery Equipment > 50 kV							
40	1825-2	Storage Battery Equipment <50 kV							
41	1830	Poles, Towers and Fixtures							
42	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery							
43	1830-4	Poles, Towers and Fixtures - Primary							
44	1830-5	Poles, Towers and Fixtures - Secondary							
45	1835	Overhead Conductors and Devices							
46	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery							
47	1835-4	Overhead Conductors and Devices - Primary							
48	1835-5	Overhead Conductors and Devices - Secondary							
49	1840	Underground Conduit							
50	1840-3	Underground Conduit - Bulk Delivery							
51	1840-4	Underground Conduit - Primary							
52	1840-5	Underground Conduit - Secondary							
53	1845	Underground Conductors and Devices							
54	1845-3	Underground Conductors and Devices - Bulk Delivery							
55	1845-4	Underground Conductors and Devices - Primary							
56	1845-5	Underground Conductors and Devices - Secondary							
57	1850	Line Transformers							
58	1855	Services							
59	1860	Meters							
60	1905	Land							
61	1906	Land Rights							
62	1908	Buildings and Fixtures							
63	1910	Leasehold Improvements							

	A	B	C	D	E	F	N	O	AC
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Large User > 5MW	Street Light	Total - Demand
64	1915	Office Furniture and Equipment							
65	1920	Computer Equipment - Hardware							
66	1925	Computer Software							
67	1930	Transportation Equipment							
68	1935	Stores Equipment							
69	1940	Tools, Shop and Garage Equipment							
70	1945	Measurement and Testing Equipment							
71	1950	Power Operated Equipment							
72	1955	Communication Equipment							
73	1960	Miscellaneous Equipment							
74	1970	Load Management Controls - Customer Premises							
75	1975	Load Management Controls - Utility Premises							
76	1980	System Supervisory Equipment							
77	1990	Other Tangible Property							
78	1995	Contributions and Grants - Credit							
79	2005	Property Under Capital Leases							
80	2010	Electric Plant Purchased or Sold							
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment							
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles							
83	3046	Balance Transferred From Income							
84	4080	Distribution Services Revenue							
85	4082	Retail Services Revenues							
86	4084	Service Transaction Requests (STR) Revenues							
87	4090	Electric Services Incidental to Energy Sales							
88	4205	Interdepartmental Rents							
89	4210	Rent from Electric Property							

	A	B	C	D	E	F	N	O	AC
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Large User > 5MW	Street Light	Total - Demand
90	[redacted]	[redacted]							
91	[redacted]	[redacted]							
92	[redacted]	[redacted]							
93	[redacted]	[redacted]							
94	4240	Provision for Rate Refunds							
95	[redacted]	[redacted]							
96	4305	Regulatory Debits							
97	4310	Regulatory Credits							
98	[redacted]	[redacted]							
99	[redacted]	[redacted]							
100	[redacted]	[redacted]							
101	[redacted]	[redacted]							
102	[redacted]	[redacted]							
103	[redacted]	[redacted]							
104	[redacted]	[redacted]							
105	[redacted]	[redacted]							
106	[redacted]	[redacted]							
107	[redacted]	[redacted]							
108	[redacted]	[redacted]							
109	[redacted]	[redacted]							
110	[redacted]	[redacted]							
111	[redacted]	[redacted]							
112	[redacted]	[redacted]							
113	[redacted]	[redacted]							
114	[redacted]	[redacted]							
115	4705	Power Purchased							
116	4708	Charges-WMS							
117	4710	Cost of Power Adjustments							
118	4712	Charges-One-Time							
119	4714	Charges-NW							
120	4715	System Control and Load Dispatching							
121	4716	Charges-CN							
122	4730	Rural Rate Assistance Expense							
123	5005	Operation Supervision and Engineering							
124	5010	Load Dispatching							
125	5012	Station Buildings and Fixtures Expense							
126	5014	Transformer Station Equipment - Operation Labour							
127	5015	Transformer Station Equipment - Operation Supplies and Expenses							
128	5016	Distribution Station Equipment - Operation Labour							
129	5017	Distribution Station Equipment - Operation Supplies and Expenses							
130	5020	Overhead Distribution Lines and Feeders - Operation Labour							
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses							
132	5030	Overhead Subtransmission Feeders - Operation							
133	5035	Overhead Distribution Transformers- Operation							
134	5040	Underground Distribution Lines and Feeders - Operation Labour							
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses							
136	5050	Underground Subtransmission Feeders - Operation							
137	5055	Underground Distribution Transformers - Operation							
138	5065	Meter Expense							

	A	B	C	D	E	F	N	O	AC
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Large User > 5MW	Street Light	Total - Demand
139	5070	Customer Premises - Operation Labour							
140	5075	Customer Premises - Materials and Expenses							
141	5085	Miscellaneous Distribution Expense							
142	5090	Underground Distribution Lines and Feeders - Rental Paid							
143	5095	Overhead Distribution Lines and Feeders - Rental Paid							
144	5096	Other Rent							
145	5105	Maintenance Supervision and Engineering							
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations							
147	5112	Maintenance of Transformer Station Equipment							
148	5114	Maintenance of Distribution Station Equipment							
149	5120	Maintenance of Poles, Towers and Fixtures							
150	5125	Maintenance of Overhead Conductors and Devices							
151	5130	Maintenance of Overhead Services							
152	5135	Overhead Distribution Lines and Feeders - Right of Way							
153	5145	Maintenance of Underground Conduit							
154	5150	Maintenance of Underground Conductors and Devices							
155	5155	Maintenance of Underground Services							
156	5160	Maintenance of Line Transformers							
157	5175	Maintenance of Meters							
158	5305	Supervision							
159	5310	Meter Reading Expense							
160	5315	Customer Billing							
161	5320	Collecting							
162	5325	Collecting - Cash Over and Short							
163	5330	Collection Charges							
164	5335	Bad Debt Expense							
165	5340	Miscellaneous Customer Accounts Expenses							
166	5405	Supervision							
167	5410	Community Relations - Sundry							
168	5415	Energy Conservation							
169	5420	Community Safety Program							
170	5425	Miscellaneous Customer Service and Informational Expenses							
171	5505	Supervision							
172	5510	Demonstrating and Selling Expense							
173	5515	Advertising Expense							
174	5520	Miscellaneous Sales Expense							
175	5605	Executive Salaries and Expenses							
176	5610	Management Salaries and Expenses							
177	5615	General Administrative Salaries and Expenses							
178	5620	Office Supplies and Expenses							
179	5625	Administrative Expense Transferred Credit							
180	5630	Outside Services Employed							
181	5635	Property Insurance							
182	5640	Injuries and Damages							
183	5645	Employee Pensions and Benefits							
184	5650	Franchise Requirements							
185	5655	Regulatory Expenses							
186	5660	General Advertising Expenses							
187	5665	Miscellaneous General Expenses							
188	5670	Rent							
189	5675	Maintenance of General Plant							
190	5680	Electrical Safety Authority Fees							
191	5685	Independent Market Operator Fees and Penalties							
192	5705	Amortization Expense - Property, Plant, and Equipment							
193	5710	Amortization of Limited Term Electric Plant							
194	5715	Amortization of Intangibles and Other Electric Plant							
195	5720	Amortization of Electric Plant Acquisition Adjustments							

2006 COST ALLOCATION INFORMATION FILING

Enersource Hydro Mississauga

EB-2005-0360 EB-2006-0247

Monday, January 15, 2007

Sheet O5 Details of Allocators by Class and Account Worksheet - Fir

Uniform System of Accounts - Detail Accounts

					Categorization	Allocation - Customer Related 1	2	3	4	5	6	7
USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
1565	Conservation and Demand Management Expenditures and Recoveries											
1608	Franchises and Consents											
1805	Land											
1805-1	Land Station >50 kV											
1805-2	Land Station <50 kV											
1806	Land Rights											
1806-1	Land Rights Station >50 kV											
1806-2	Land Rights Station <50 kV											
1808	Buildings and Fixtures											
1808-1	Buildings and Fixtures > 50 kV											
1808-2	Buildings and Fixtures < 50 KV											
1810	Leasehold Improvements											
1810-1	Leasehold Improvements >50 kV											
1810-2	Leasehold Improvements <50 kV											
1815	Transformer Station Equipment - Normally Primary above 50 kV											
1820	Distribution Station Equipment - Normally Primary below 50 kV											
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)											
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)											
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)											
1825	Storage Battery Equipment											
1825-1	Storage Battery Equipment > 50 kV											
1825-2	Storage Battery Equipment <50 kV											
1830	Poles, Towers and Fixtures											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery											
1830-4	Poles, Towers and Fixtures - Primary											
1830-5	Poles, Towers and Fixtures - Secondary											
1835	Overhead Conductors and Devices											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery											
1835-4	Overhead Conductors and Devices - Primary											
1835-5	Overhead Conductors and Devices - Secondary											
1840	Underground Conduit											
1840-3	Underground Conduit - Bulk Delivery											
1840-4	Underground Conduit - Primary											
1840-5	Underground Conduit - Secondary											
1845	Underground Conductors and Devices											
1845-3	Underground Conductors and Devices - Bulk Delivery											
1845-4	Underground Conductors and Devices - Primary											
1845-5	Underground Conductors and Devices - Secondary											
1850	Line Transformers											
1855	Services											
1860	Meters											
1905	Land											
1906	Land Rights											
1908	Buildings and Fixtures											
1910	Leasehold Improvements											

	A	B	C	D	E	F	AD	AE	AF	AG	AH	AI	AJ
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
64	1915	Office Furniture and Equipment											
65	1920	Computer Equipment - Hardware											
66	1925	Computer Software											
67	1930	Transportation Equipment											
68	1935	Stores Equipment											
69	1940	Tools, Shop and Garage Equipment											
70	1945	Measurement and Testing Equipment											
71	1950	Power Operated Equipment											
72	1955	Communication Equipment											
73	1960	Miscellaneous Equipment											
74	1970	Load Management Controls - Customer Premises											
75	1975	Load Management Controls - Utility Premises											
76	1980	System Supervisory Equipment											
77	1990	Other Tangible Property											
78	1995	Contributions and Grants - Credit											
79	2005	Property Under Capital Leases											
80	2010	Electric Plant Purchased or Sold											
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment											
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles											
83	3046	Balance Transferred From Income											
84	4080	Distribution Services Revenue											
85	4082	Retail Services Revenues											
86	4084	Service Transaction Requests (STR) Revenues											
87	4090	Electric Services Incidental to Energy Sales											
88	4205	Interdepartmental Rents											
89	4210	Rent from Electric Property											

	A	B	C	D	E	F	AD	AE	AF	AG	AH	AI	AJ
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
90	4215	Other Utility Operating Income											
91	4220	Other Electric Revenues											
92	4225	Late Payment Charges											
93	4235	Miscellaneous Service Revenues											
94	4240	Provision for Rate Refunds											
95	4245	Government Assistance Directly Credited to Income											
96	4305	Regulatory Debits											
97	4310	Regulatory Credits											
98	4315	Revenues from Electric Plant Leased to Others											
99	4320	Expenses of Electric Plant Leased to Others											
100	4325	Revenues from Merchandise, Jobbing, Etc.											
101	4330	Costs and Expenses of Merchandising, Jobbing, Etc											
102	4335	Profits and Losses from Financial Instrument Hedges											
103	4340	Profits and Losses from Financial Instrument Investments											
104	4345	Gains from Disposition of Future Use Utility Plant											
105	4350	Losses from Disposition of Future Use Utility Plant											
106	4355	Gain on Disposition of Utility and Other Property											
107	4360	Loss on Disposition of Utility and Other Property											
108	4365	Gains from Disposition of Allowances for Emission											
109	4370	Losses from Disposition of Allowances for Emission											
110	4390	Miscellaneous Non-Operating Income											
111	4395	Rate-Payer Benefit Including Interest											
112	4398	Foreign Exchange Gains and Losses, Including Amortization											
113	4405	Interest and Dividend Income											
114	4415	Equity in Earnings of Subsidiary Companies											
115	4705	Power Purchased											
116	4708	Charges-WMS											
117	4710	Cost of Power Adjustments											
118	4712	Charges-One-Time											
119	4714	Charges-NW											
120	4715	System Control and Load Dispatching											
121	4716	Charges-CN											
122	4730	Rural Rate Assistance Expense											
123	5005	Operation Supervision and Engineering											
124	5010	Load Dispatching											
125	5012	Station Buildings and Fixtures Expense											
126	5014	Transformer Station Equipment - Operation Labour											
127	5015	Transformer Station Equipment - Operation Supplies and Expenses											
128	5016	Distribution Station Equipment - Operation Labour											
129	5017	Distribution Station Equipment - Operation Supplies and Expenses											
130	5020	Overhead Distribution Lines and Feeders - Operation Labour											
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses											
132	5030	Overhead Subtransmission Feeders - Operation											
133	5035	Overhead Distribution Transformers- Operation											
134	5040	Underground Distribution Lines and Feeders - Operation Labour											
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses											
136	5050	Underground Subtransmission Feeders - Operation											
137	5055	Underground Distribution Transformers - Operation											
138	5065	Meter Expense											

	A	B	C	D	E	F	AD	AE	AF	AG	AH	AI	AJ
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out Includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
139	5070	Customer Premises - Operation Labour											
140	5075	Customer Premises - Materials and Expenses											
141	5085	Miscellaneous Distribution Expense											
142	5090	Underground Distribution Lines and Feeders - Rental Paid											
143	5095	Overhead Distribution Lines and Feeders - Rental Paid											
144	5096	Other Rent											
145	5105	Maintenance Supervision and Engineering											
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations											
147	5112	Maintenance of Transformer Station Equipment											
148	5114	Maintenance of Distribution Station Equipment											
149	5120	Maintenance of Poles, Towers and Fixtures											
150	5125	Maintenance of Overhead Conductors and Devices											
151	5130	Maintenance of Overhead Services											
152	5135	Overhead Distribution Lines and Feeders - Right of Way											
153	5145	Maintenance of Underground Conduit											
154	5150	Maintenance of Underground Conductors and Devices											
155	5155	Maintenance of Underground Services											
156	5160	Maintenance of Line Transformers											
157	[redacted]												
158													
159													
160													
161													
162													
163													
164													
165													
166	5405	Supervision											
167	5410	Community Relations - Sundry											
168	5415	Energy Conservation											
169	5420	Community Safety Program											
170	5425	Miscellaneous Customer Service and Informational Expenses											
171	5505	Supervision											
172	5510	Demonstrating and Selling Expense											
173	5515	Advertising Expense											
174	5520	Miscellaneous Sales Expense											
175	5605	Executive Salaries and Expenses											
176	5610	Management Salaries and Expenses											
177	5615	General Administrative Salaries and Expenses											
178	5620	Office Supplies and Expenses											
179	5625	Administrative Expense Transferred Credit											
180	5630	Outside Services Employed											
181	5635	Property Insurance											
182	5640	Injuries and Damages											
183	5645	Employee Pensions and Benefits											
184	5650	Franchise Requirements											
185	5655	Regulatory Expenses											
186	5660	General Advertising Expenses											
187	5665	Miscellaneous General Expenses											
188	5670	Rent											
189	5675	Maintenance of General Plant											
190	5680	Electrical Safety Authority Fees											
191	5685	Independent Market Operator Fees and Penalties											
192	5705	Amortization Expense - Property, Plant, and Equipment											
193	5710	Amortization of Limited Term Electric Plant											
194	5715	Amortization of Intangibles and Other Electric Plant											
195	5720	Amortization of Electric Plant Acquisition Adjustments											

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Sheet O5 Details of Allocators by Class and Account Worksheet - Fir

Uniform System of Accounts - Detail Accounts

Row	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand (Categorization)	Total - Customer
19	1565	Conservation and Demand Management Expenditures and Recoveries					
20	1606	Franchises and Consents					
21	1805	Land					
22	1805-1	Land Station >50 kV					
23	1805-2	Land Station <50 kV					
24	1806	Land Rights					
25	1806-1	Land Rights Station >50 kV					
26	1806-2	Land Rights Station <50 kV					
27	1808	Buildings and Fixtures					
28	1808-1	Buildings and Fixtures > 50 kV					
29	1808-2	Buildings and Fixtures < 50 KV					
30	1810	Leasehold Improvements					
31	1810-1	Leasehold Improvements >50 kV					
32	1810-2	Leasehold Improvements <50 kV					
33	1815	Transformer Station Equipment - Normally Primary above 50 kV					
34	1820	Distribution Station Equipment - Normally Primary below 50 kV					
35	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)					
36	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)					
37	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)					
38	1825	Storage Battery Equipment					
39	1825-1	Storage Battery Equipment > 50 kV					
40	1825-2	Storage Battery Equipment <50 kV					
41	1830	Poles, Towers and Fixtures					
42	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery					
43	1830-4	Poles, Towers and Fixtures - Primary					
44	1830-5	Poles, Towers and Fixtures - Secondary					
45	1835	Overhead Conductors and Devices					
46	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery					
47	1835-4	Overhead Conductors and Devices - Primary					
48	1835-5	Overhead Conductors and Devices - Secondary					
49	1840	Underground Conduit					
50	1840-3	Underground Conduit - Bulk Delivery					
51	1840-4	Underground Conduit - Primary					
52	1840-5	Underground Conduit - Secondary					
53	1845	Underground Conductors and Devices					
54	1845-3	Underground Conductors and Devices - Bulk Delivery					
55	1845-4	Underground Conductors and Devices - Primary					
56	1845-5	Underground Conductors and Devices - Secondary					
57	1850	Line Transformers					
58	1855	Services					
59	1860	Meters					
60	1905	Land					
61	1906	Land Rights					
62	1908	Buildings and Fixtures					
63	1910	Leasehold Improvements					

	A	B	C	D	E	F	AX
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Total - Customer
64	1915	Office Furniture and Equipment					
65	1920	Computer Equipment - Hardware					
66	1925	Computer Software					
67	1930	Transportation Equipment					
68	1935	Stores Equipment					
69	1940	Tools, Shop and Garage Equipment					
70	1945	Measurement and Testing Equipment					
71	1950	Power Operated Equipment					
72	1955	Communication Equipment					
73	1960	Miscellaneous Equipment					
74	1970	Load Management Controls - Customer Premises					
75	1975	Load Management Controls - Utility Premises					
76	1980	System Supervisory Equipment					
77	1990	Other Tangible Property					
78	1995	Contributions and Grants - Credit					
79	2005	Property Under Capital Leases					
80	2010	Electric Plant Purchased or Sold					
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment					
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles					
83	3046	Balance Transferred From Income					
84	4080	Distribution Services Revenue					
85	4082	Retail Services Revenues					
86	4084	Service Transaction Requests (STR) Revenues					
87	4090	Electric Services Incidental to Energy Sales					
88	4205	Interdepartmental Rents					
89	4210	Rent from Electric Property					

18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Total - Customer
90	4215	Other Utility Operating Income					
91	4220	Other Electric Revenues					
92	4225	Late Payment Charges					
93	4235	Miscellaneous Service Revenues					
94	4240	Provision for Rate Refunds					
95	4245	Government Assistance Directly Credited to Income					
96	4305	Regulatory Debits					
97	4310	Regulatory Credits					
98	4315	Revenues from Electric Plant Leased to Others					
99	4320	Expenses of Electric Plant Leased to Others					
100	4325	Revenues from Merchandise, Jobbing, Etc					
101	4330	Costs and Expenses of Merchandising, Jobbing, Etc					
102	4335	Profits and Losses from Financial Instrument Hedges					
103	4340	Profits and Losses from Financial Instrument Investments					
104	4345	Gains from Disposition of Future Use Utility Plant					
105	4350	Losses from Disposition of Future Use Utility Plant					
106	4355	Gain on Disposition of Utility and Other Property					
107	4360	Loss on Disposition of Utility and Other Property					
108	4365	Gains from Disposition of Allowances for Emission					
109	4370	Losses from Disposition of Allowances for Emission					
110	4390	Miscellaneous Non-Operating Income					
111	4395	Rate-Payer Benefit Including Interest					
112	4398	Foreign Exchange Gains and Losses, Including Amortization					
113	4405	Interest and Dividend Income					
114	4415	Equity in Earnings of Subsidiary Companies					
115	4705	Power Purchased					
116	4708	Charges-WMS					
117	4710	Cost of Power Adjustments					
118	4712	Charges-One-Time					
119	4714	Charges-NW					
120	4715	System Control and Load Dispatching					
121	4716	Charges-CN					
122	4730	Rural Rate Assistance Expense					
123	5005	Operation Supervision and Engineering					
124	5010	Load Dispatching					
125	5012	Station Buildings and Fixtures Expense					
126	5014	Transformer Station Equipment - Operation Labour					
127	5015	Transformer Station Equipment - Operation Supplies and Expenses					
128	5016	Distribution Station Equipment - Operation Labour					
129	5017	Distribution Station Equipment - Operation Supplies and Expenses					
130	5020	Overhead Distribution Lines and Feeders - Operation Labour					
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses					
132	5030	Overhead Subtransmission Feeders - Operation					
133	5035	Overhead Distribution Transformers- Operation					
134	5040	Underground Distribution Lines and Feeders - Operation Labour					
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses					
136	5050	Underground Subtransmission Feeders - Operation					
137	5055	Underground Distribution Transformers - Operation					
138	5065	Meter Expense					

	A	B	C	D	E	F	AX
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Total - Customer
139	5070	Customer Premises - Operation Labour					
140	5075	Customer Premises - Materials and Expenses					
141	5085	Miscellaneous Distribution Expense					
142	5090	Underground Distribution Lines and Feeders - Rental Paid					
143	5095	Overhead Distribution Lines and Feeders - Rental Paid					
144	5096	Other Rent					
145	5105	Maintenance Supervision and Engineering					
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations					
147	5112	Maintenance of Transformer Station Equipment					
148	5114	Maintenance of Distribution Station Equipment					
149	5120	Maintenance of Poles, Towers and Fixtures					
150	5125	Maintenance of Overhead Conductors and Devices					
151	5130	Maintenance of Overhead Services					
152	5135	Overhead Distribution Lines and Feeders - Right of Way					
153	5145	Maintenance of Underground Conduit					
154	5150	Maintenance of Underground Conductors and Devices					
155	5155	Maintenance of Underground Services					
156	5160	Maintenance of Line Transformers					
157	5175	Maintenance of Meters					
158	5305	Supervision					
159	5310	Meter Reading Expense					
160	5315	Customer Billing					
161	5320	Collecting					
162	5325	Collecting- Cash Over and Short					
163	5330	Collection Charges					
164	5335	Bad Debt Expense					
165	5340	Miscellaneous Customer Accounts Expenses					
166	5405	Supervision					
167	5410	Community Relations - Sundry					
168	5415	Energy Conservation					
169	5420	Community Safety Program					
170	5425	Miscellaneous Customer Service and Informational Expenses					
171	5505	Supervision					
172	5510	Demonstrating and Selling Expense					
173	5515	Advertising Expense					
174	5520	Miscellaneous Sales Expense					
175	5605	Executive Salaries and Expenses					
176	5610	Management Salaries and Expenses					
177	5615	General Administrative Salaries and Expenses					
178	5620	Office Supplies and Expenses					
179	5625	Administrative Expense Transferred Credit					
180	5630	Outside Services Employed					
181	5635	Property Insurance					
182	5640	Injuries and Damages					
183	5645	Employee Pensions and Benefits					
184	5650	Franchise Requirements					
185	5655	Regulatory Expenses					
186	5660	General Advertising Expenses					
187	5665	Miscellaneous General Expenses					
188	5670	Rent					
189	5675	Maintenance of General Plant					
190	5680	Electrical Safety Authority Fees					
191	5685	Independent Market Operator Fees and Penalties					
192	5705	Amortization Expense - Property, Plant, and Equipment					
193	5710	Amortization of Limited Term Electric Plant					
194	5715	Amortization of Intangibles and Other Electric Plant					
195	5720	Amortization of Electric Plant Acquisition Adjustments					

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						Categorization	Allocation of Miscellaneous Revenue 1	2	3	4	5	6	7
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
19	1565	Conservation and Demand Management Expenditures and Recoveries											
20	1608	Franchises and Consents											
21	1805	Land											
22	1805-1	Land Station >50 kV											
23	1805-2	Land Station <50 kV											
24	1806	Land Rights											
25	1806-1	Land Rights Station >50 kV											
26	1806-2	Land Rights Station <50 kV											
27	1808	Buildings and Fixtures											
28	1808-1	Buildings and Fixtures > 50 kV											
29	1808-2	Buildings and Fixtures < 50 KV											
30	1810	Leasehold Improvements											
31	1810-1	Leasehold Improvements >50 kV											
32	1810-2	Leasehold Improvements <50 kV											
33	1815	Transformer Station Equipment - Normally Primary above 50 kV											
34	1820	Distribution Station Equipment - Normally Primary below 50 kV											
35	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)											
36	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)											
37	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)											
38	1825	Storage Battery Equipment											
39	1825-1	Storage Battery Equipment > 50 kV											
40	1825-2	Storage Battery Equipment <50 kV											
41	1830	Poles, Towers and Fixtures											
42	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery											
43	1830-4	Poles, Towers and Fixtures - Primary											
44	1830-5	Poles, Towers and Fixtures - Secondary											
45	1835	Overhead Conductors and Devices											
46	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery											
47	1835-4	Overhead Conductors and Devices - Primary											
48	1835-5	Overhead Conductors and Devices - Secondary											
49	1840	Underground Conduit											
50	1840-3	Underground Conduit - Bulk Delivery											
51	1840-4	Underground Conduit - Primary											
52	1840-5	Underground Conduit - Secondary											
53	1845	Underground Conductors and Devices											
54	1845-3	Underground Conductors and Devices - Bulk Delivery											
55	1845-4	Underground Conductors and Devices - Primary											
56	1845-5	Underground Conductors and Devices - Secondary											
57	1850	Line Transformers											
58	1855	Services											
59	1860	Meters											
60	1905	Land											
61	1906	Land Rights											
62	1908	Buildings and Fixtures											
63	1910	Leasehold Improvements											

	A	B	C	D	E	F	AY	AZ	BA	BB	BC	BD	BE
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
64	1915	Office Furniture and Equipment											
65	1920	Computer Equipment - Hardware											
66	1925	Computer Software											
67	1930	Transportation Equipment											
68	1935	Stores Equipment											
69	1940	Tools, Shop and Garage Equipment											
70	1945	Measurement and Testing Equipment											
71	1950	Power Operated Equipment											
72	1955	Communication Equipment											
73	1960	Miscellaneous Equipment											
74	1970	Load Management Controls - Customer Premises											
75	1975	Load Management Controls - Utility Premises											
76	1980	System Supervisory Equipment											
77	1990	Other Tangible Property											
78	1995	Contributions and Grants - Credit											
79	2005	Property Under Capital Leases											
80	2010	Electric Plant Purchased or Sold											
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment											
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles											
83	3046	Balance Transferred From Income											
84	4080	Distribution Services Revenue											
85	4082	Retail Services Revenues											
86	4084	Service Transaction Requests (STR) Revenues											
87	4090	Electric Services Incidental to Energy Sales											
88	4205	Interdepartmental Rents											
89	4210	Rent from Electric Property											

	A	B	C	D	E	F	AY	AZ	BA	BB	BC	BD	BE
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
90	4215	Other Utility Operating Income											
91	4220	Other Electric Revenues											
92	4225	Late Payment Charges											
93	4235	Miscellaneous Service Revenues											
94	4240	Provision for Rate Refunds											
95	4245	Government Assistance Directly Credited to Income											
96	4305	Regulatory Debits											
97	4310	Regulatory Credits											
98	4315	Revenues from Electric Plant Leased to Others											
99	4320	Expenses of Electric Plant Leased to Others											
100	4325	Revenues from Merchandise, Jobbing, Etc											
101	4330	Costs and Expenses of Merchandising, Jobbing, Etc											
102	4335	Profits and Losses from Financial Instrument Hedges											
103	4340	Profits and Losses from Financial Instrument Investments											
104	4345	Gains from Disposition of Future Use Utility Plant											
105	4350	Losses from Disposition of Future Use Utility Plant											
106	4355	Gain on Disposition of Utility and Other Property											
107	4360	Loss on Disposition of Utility and Other Property											
108	4365	Gains from Disposition of Allowances for Emission											
109	4370	Losses from Disposition of Allowances for Emission											
110	4390	Miscellaneous Non-Operating Income											
111	4395	Rate-Payer Benefit Including Interest											
112	4398	Foreign Exchange Gains and Losses, Including Amortization											
113	4405	Interest and Dividend Income											
114	4415	Equity in Earnings of Subsidiary Companies											
115	4705	Power Purchased											
116	4708	Charges-WMS											
117	4710	Cost of Power Adjustments											
118	4712	Charges-One-Time											
119	4714	Charges-NW											
120	4715	System Control and Load Dispatching											
121	4716	Charges-CN											
122	4730	Rural Rate Assistance Expense											
123	5005	Operation Supervision and Engineering											
124	5010	Load Dispatching											
125	5012	Station Buildings and Fixtures Expense											
126	5014	Transformer Station Equipment - Operation Labour											
127	5015	Transformer Station Equipment - Operation Supplies and Expenses											
128	5016	Distribution Station Equipment - Operation Labour											
129	5017	Distribution Station Equipment - Operation Supplies and Expenses											
130	5020	Overhead Distribution Lines and Feeders - Operation Labour											
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses											
132	5030	Overhead Subtransmission Feeders - Operation											
133	5035	Overhead Distribution Transformers- Operation											
134	5040	Underground Distribution Lines and Feeders - Operation Labour											
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses											
136	5050	Underground Subtransmission Feeders - Operation											
137	5055	Underground Distribution Transformers - Operation											
138	5065	Meter Expense											

	A	B	C	D	E	F	AY	AZ	BA	BB	BC	BD	BE
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
139	5070	Customer Premises - Operation Labour											
140	5075	Customer Premises - Materials and Expenses											
141	5085	Miscellaneous Distribution Expense											
142	5090	Underground Distribution Lines and Feeders - Rental Paid											
143	5095	Overhead Distribution Lines and Feeders - Rental Paid											
144	5096	Other Rent											
145	5105	Maintenance Supervision and Engineering											
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations											
147	5112	Maintenance of Transformer Station Equipment											
148	5114	Maintenance of Distribution Station Equipment											
149	5120	Maintenance of Poles, Towers and Fixtures											
150	5125	Maintenance of Overhead Conductors and Devices											
151	5130	Maintenance of Overhead Services											
152	5135	Overhead Distribution Lines and Feeders - Right of Way											
153	5145	Maintenance of Underground Conduit											
154	5150	Maintenance of Underground Conductors and Devices											
155	5155	Maintenance of Underground Services											
156	5160	Maintenance of Line Transformers											
157	5175	Maintenance of Meters											
158	5305	Supervision											
159	5310	Meter Reading Expense											
160	5315	Customer Billing											
161	5320	Collecting											
162	5325	Collecting - Cash Over and Short											
163	5330	Collection Charges											
164	5335	Bad Debt Expense											
165	5340	Miscellaneous Customer Accounts Expenses											
166	5405	Supervision											
167	5410	Community Relations - Sundry											
168	5415	Energy Conservation											
169	5420	Community Safety Program											
170	5425	Miscellaneous Customer Service and Informational Expenses											
171	5505	Supervision											
172	5510	Demonstrating and Selling Expense											
173	5515	Advertising Expense											
174	5520	Miscellaneous Sales Expense											
175	5605	Executive Salaries and Expenses											
176	5610	Management Salaries and Expenses											
177	5615	General Administrative Salaries and Expenses											
178	5620	Office Supplies and Expenses											
179	5625	Administrative Expense Transferred Credit											
180	5630	Outside Services Employed											
181	5635	Property Insurance											
182	5640	Injuries and Damages											
183	5645	Employee Pensions and Benefits											
184	5650	Franchise Requirements											
185	5655	Regulatory Expenses											
186	5660	General Advertising Expenses											
187	5665	Miscellaneous General Expenses											
188	5670	Rent											
189	5675	Maintenance of General Plant											
190	5680	Electrical Safety Authority Fees											
191	5685	Independent Market Operator Fees and Penalties											
192	5705	Amortization Expense - Property, Plant, and Equipment											
193	5710	Amortization of Limited Term Electric Plant											
194	5715	Amortization of Intangibles and Other Electric Plant											
195	5720	Amortization of Electric Plant Acquisition Adjustments											

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	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Categorization: Demand	Total - Mis	Allocation of General Plant and Administration: 1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW
19	1565	Conservation and Demand Management Expenditures and Recoveries											
20	1608	Franchises and Consents											
21	1805	Land											
22	1805-1	Land Station >50 kV											
23	1805-2	Land Station <50 kV											
24	1806	Land Rights											
25	1806-1	Land Rights Station >50 kV											
26	1806-2	Land Rights Station <50 kV											
27	1808	Buildings and Fixtures											
28	1808-1	Buildings and Fixtures > 50 kV											
29	1808-2	Buildings and Fixtures < 50 KV											
30	1810	Leasehold Improvements											
31	1810-1	Leasehold Improvements >50 kV											
32	1810-2	Leasehold Improvements <50 kV											
33	1815	Transformer Station Equipment - Normally Primary above 50 kV											
34	1820	Distribution Station Equipment - Normally Primary below 50 kV											
35	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)											
36	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)											
37	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)											
38	1825	Storage Battery Equipment											
39	1825-1	Storage Battery Equipment > 50 kV											
40	1825-2	Storage Battery Equipment <50 kV											
41	1830	Poles, Towers and Fixtures											
42	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery											
43	1830-4	Poles, Towers and Fixtures - Primary											
44	1830-5	Poles, Towers and Fixtures - Secondary											
45	1835	Overhead Conductors and Devices											
46	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery											
47	1835-4	Overhead Conductors and Devices - Primary											
48	1835-5	Overhead Conductors and Devices - Secondary											
49	1840	Underground Conduit											
50	1840-3	Underground Conduit - Bulk Delivery											
51	1840-4	Underground Conduit - Primary											
52	1840-5	Underground Conduit - Secondary											
53	1845	Underground Conductors and Devices											
54	1845-3	Underground Conductors and Devices - Bulk Delivery											
55	1845-4	Underground Conductors and Devices - Primary											
56	1845-5	Underground Conductors and Devices - Secondary											
57	1850	Line Transformers											
58	1855	Services											
59	1860	Meters											
60	1905	Land											
61	1906	Land Rights											
62	1908	Buildings and Fixtures											
63	1910	Leasehold Improvements											

	A	B	C	D	E	F	BS	BT	BU	BV	BW	BX	BY
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Total - Mis	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW
64	1915	Office Furniture and Equipment											
65	1920	Computer Equipment - Hardware											
66	1925	Computer Software											
67	1930	Transportation Equipment											
68	1935	Stores Equipment											
69	1940	Tools, Shop and Garage Equipment											
70	1945	Measurement and Testing Equipment											
71	1950	Power Operated Equipment											
72	1955	Communication Equipment											
73	1960	Miscellaneous Equipment											
74	1970	Load Management Controls - Customer Premises											
75	1975	Load Management Controls - Utility Premises											
76	1980	System Supervisory Equipment											
77	1990	Other Tangible Property											
78	1995	Contributions and Grants - Credit											
79	2005	Property Under Capital Leases											
80	2010	Electric Plant Purchased or Sold											
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment											
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles											
83	3046	Balance Transferred From Income											
84	4080	Distribution Services Revenue											
85	4082	Retail Services Revenues											
86	4084	Service Transaction Requests (STR) Revenues											
87	4090	Electric Services Incidental to Energy Sales											
88	4205	Interdepartmental Rents											
89	4210	Rent from Electric Property											

	A	B	C	D	E	F	BS	BT	BU	BV	BW	BX	BY
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Total - Mis	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW
90	4215	Other Utility Operating Income											
91	4220	Other Electric Revenues											
92	4225	Late Payment Charges											
93	4235	Miscellaneous Service Revenues											
94	4240	Provision for Rate Refunds											
95	4245	Government Assistance Directly Credited to Income											
96	4305	Regulatory Debits											
97	4310	Regulatory Credits											
98	4315	Revenues from Electric Plant Leased to Others											
99	4320	Expenses of Electric Plant Leased to Others											
100	4325	Revenues from Merchandise, Jobbing, Etc											
101	4330	Costs and Expenses of Merchandising, Jobbing, Etc											
102	4335	Profits and Losses from Financial Instrument Hedges											
103	4340	Profits and Losses from Financial Instrument Investments											
104	4345	Gains from Disposition of Future Use Utility Plant											
105	4350	Losses from Disposition of Future Use Utility Plant											
106	4355	Gain on Disposition of Utility and Other Property											
107	4360	Loss on Disposition of Utility and Other Property											
108	4365	Gains from Disposition of Allowances for Emission											
109	4370	Losses from Disposition of Allowances for Emission											
110	4390	Miscellaneous Non-Operating Income											
111	4395	Rate-Payer Benefit Including Interest											
112	4398	Foreign Exchange Gains and Losses, Including Amortization											
113	4405	Interest and Dividend Income											
114	4415	Equity in Earnings of Subsidiary Companies											
115	4705	Power Purchased											
116	4708	Charges-WMS											
117	4710	Cost of Power Adjustments											
118	4712	Charges-One-Time											
119	4714	Charges-NW											
120	4715	System Control and Load Dispatching											
121	4716	Charges-CN											
122	4730	Rural Rate Assistance Expense											
123	5005	Operation Supervision and Engineering											
124	5010	Load Dispatching											
125	5012	Station Buildings and Fixtures Expense											
126	5014	Transformer Station Equipment - Operation Labour											
127	5015	Transformer Station Equipment - Operation Supplies and Expenses											
128	5016	Distribution Station Equipment - Operation Labour											
129	5017	Distribution Station Equipment - Operation Supplies and Expenses											
130	5020	Overhead Distribution Lines and Feeders - Operation Labour											
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses											
132	5030	Overhead Subtransmission Feeders - Operation											
133	5035	Overhead Distribution Transformers- Operation											
134	5040	Underground Distribution Lines and Feeders - Operation Labour											
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses											
136	5050	Underground Subtransmission Feeders - Operation											
137	5055	Underground Distribution Transformers - Operation											
138	5065	Meter Expense											

	A	B	C	D	E	F	BS	BT	BU	BV	BW	BX	BY
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Total - Mis	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW
139	5070	Customer Premises - Operation Labour											
140	5075	Customer Premises - Materials and Expenses											
141	5085	Miscellaneous Distribution Expense											
142	5090	Underground Distribution Lines and Feeders - Rental Paid											
143	5095	Overhead Distribution Lines and Feeders - Rental Paid											
144	5096	Other Rent											
145	5105	Maintenance Supervision and Engineering											
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations											
147	5112	Maintenance of Transformer Station Equipment											
148	5114	Maintenance of Distribution Station Equipment											
149	5120	Maintenance of Poles, Towers and Fixtures											
150	5125	Maintenance of Overhead Conductors and Devices											
151	5130	Maintenance of Overhead Services											
152	5135	Overhead Distribution Lines and Feeders - Right of Way											
153	5145	Maintenance of Underground Conduit											
154	5150	Maintenance of Underground Conductors and Devices											
155	5155	Maintenance of Underground Services											
156	5160	Maintenance of Line Transformers											
157	5175	Maintenance of Meters											
158	5305	Supervision											
159	5310	Meter Reading Expense											
160	5315	Customer Billing											
161	5320	Collecting											
162	5325	Collecting- Cash Over and Short											
163	5330	Collection Charges											
164	5335	Bad Debt Expense											
165	5340	Miscellaneous Customer Accounts Expenses											
166	5405	Supervision											
167	5410	Community Relations - Sundry											
168	5415	Energy Conservation											
169	5420	Community Safety Program											
170	5425	Miscellaneous Customer Service and Informational Expenses											
171	5505	Supervision											
172	5510	Demonstrating and Selling Expense											
173	5515	Advertising Expense											
174	5520	Miscellaneous Sales Expense											
175	5605	Executive Salaries and Expenses											
176	5610	Management Salaries and Expenses											
177	5615	General Administrative Salaries and Expenses											
178	5620	Office Supplies and Expenses											
179	5625	Administrative Expense Transferred Credit											
180	5630	Outside Services Employed											
181	5635	Property Insurance											
182	5640	Injuries and Damages											
183	5645	Employee Pensions and Benefits											
184	5650	Franchise Requirements											
185	5655	Regulatory Expenses											
186	5660	General Advertising Expenses											
187	5665	Miscellaneous General Expenses											
188	5670	Rent											
189	5675	Maintenance of General Plant											
190	5680	Electrical Safety Authority Fees											
191	5685	Independent Market Operator Fees and Penalties											
192	5705	Amortization Expense - Property, Plant, and Equipment											
193	5710	Amortization of Limited Term Electric Plant											
194	5715	Amortization of Intangibles and Other Electric Plant											
195	5720	Amortization of Electric Plant Acquisition Adjustments											

2006 COST ALLOCATION INFORMATION FILING

Enersource Hydro Mississauga

EB-2005-0360 EB-2006-0247

Monday, January 15, 2007

Sheet O5 Details of Allocators by Class and Account Worksheet - Fir

Uniform System of Accounts - Detail Accounts

Categorization 7

Row	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Street Light	Total - A&G
19	1565	Conservation and Demand Management Expenditures and Recoveries						
20	1606	Franchises and Consents						
21	1805	Land						
22	1805-1	Land Station >50 kV						
23	1805-2	Land Station <50 kV						
24	1806	Land Rights						
25	1806-1	Land Rights Station >50 kV						
26	1806-2	Land Rights Station <50 kV						
27	1808	Buildings and Fixtures						
28	1808-1	Buildings and Fixtures > 50 kV						
29	1808-2	Buildings and Fixtures < 50 KV						
30	1810	Leasehold Improvements						
31	1810-1	Leasehold Improvements >50 kV						
32	1810-2	Leasehold Improvements <50 kV						
33	1815	Transformer Station Equipment - Normally Primary above 50 kV						
34	1820	Distribution Station Equipment - Normally Primary below 50 kV						
35	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)						
36	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)						
37	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)						
38	1825	Storage Battery Equipment						
39	1825-1	Storage Battery Equipment > 50 kV						
40	1825-2	Storage Battery Equipment <50 kV						
41	1830	Poles, Towers and Fixtures						
42	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery						
43	1830-4	Poles, Towers and Fixtures - Primary						
44	1830-5	Poles, Towers and Fixtures - Secondary						
45	1835	Overhead Conductors and Devices						
46	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery						
47	1835-4	Overhead Conductors and Devices - Primary						
48	1835-5	Overhead Conductors and Devices - Secondary						
49	1840	Underground Conduit						
50	1840-3	Underground Conduit - Bulk Delivery						
51	1840-4	Underground Conduit - Primary						
52	1840-5	Underground Conduit - Secondary						
53	1845	Underground Conductors and Devices						
54	1845-3	Underground Conductors and Devices - Bulk Delivery						
55	1845-4	Underground Conductors and Devices - Primary						
56	1845-5	Underground Conductors and Devices - Secondary						
57	1850	Line Transformers						
58	1855	Services						
59	1860	Meters						
60	1905	Land						
61	1906	Land Rights						
62	1908	Buildings and Fixtures						
63	1910	Leasehold Improvements						

	A	B	C	D	E	F	BZ	CN	CO
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Street Light	Total - A&G	
64	1915	Office Furniture and Equipment							
65	1920	Computer Equipment - Hardware							
66	1925	Computer Software							
67	1930	Transportation Equipment							
68	1935	Stores Equipment							
69	1940	Tools, Shop and Garage Equipment							
70	1945	Measurement and Testing Equipment							
71	1950	Power Operated Equipment							
72	1955	Communication Equipment							
73	1960	Miscellaneous Equipment							
74	1970	Load Management Controls - Customer Premises							
75	1975	Load Management Controls - Utility Premises							
76	1980	System Supervisory Equipment							
77	1990	Other Tangible Property							
78	1995	Contributions and Grants - Credit							
79	2005	Property Under Capital Leases							
80	2010	Electric Plant Purchased or Sold							
81	2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment							
82	2120	Accumulated Amortization of Electric Utility Plant - Intangibles							
83	3046	Balance Transferred From Income							
84	4080	Distribution Services Revenue							
85	4082	Retail Services Revenues							
86	4084	Service Transaction Requests (STR) Revenues							
87	4090	Electric Services Incidental to Energy Sales							
88	4205	Interdepartmental Rents							
89	4210	Rent from Electric Property							

	A	B	C	D	E	F	BZ	CN	CO
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Street Light	Total - A&G	
90	4215	Other Utility Operating Income							
91	4220	Other Electric Revenues							
92	4225	Late Payment Charges							
93	4235	Miscellaneous Service Revenues							
94	4240	Provision for Rate Refunds							
95	4245	Government Assistance Directly Credited to Income							
96	4305	Regulatory Debits							
97	4310	Regulatory Credits							
98	4315	Revenues from Electric Plant Leased to Others							
99	4320	Expenses of Electric Plant Leased to Others							
100	4325	Revenues from Merchandise, Jobbing, Etc.							
101	4330	Costs and Expenses of Merchandising, Jobbing, Etc.							
102	4335	Profits and Losses from Financial Instrument Hedges							
103	4340	Profits and Losses from Financial Instrument Investments							
104	4345	Gains from Disposition of Future Use Utility Plant							
105	4350	Losses from Disposition of Future Use Utility Plant							
106	4355	Gain on Disposition of Utility and Other Property							
107	4360	Loss on Disposition of Utility and Other Property							
108	4365	Gains from Disposition of Allowances for Emission							
109	4370	Losses from Disposition of Allowances for Emission							
110	4390	Miscellaneous Non-Operating Income							
111	4395	Rate-Payer Benefit Including Interest							
112	4398	Foreign Exchange Gains and Losses, Including Amortization							
113	4405	Interest and Dividend Income							
114	4415	Equity in Earnings of Subsidiary Companies							
115	4705	Power Purchased							
116	4708	Charges-WMS							
117	4710	Cost of Power Adjustments							
118	4712	Charges-One-Time							
119	4714	Charges-NW							
120	4715	System Control and Load Dispatching							
121	4716	Charges-CN							
122	4730	Rural Rate Assistance Expense							
123	5005	Operation Supervision and Engineering							
124	5010	Load Dispatching							
125	5012	Station Buildings and Fixtures Expense							
126	5014	Transformer Station Equipment - Operation Labour							
127	5015	Transformer Station Equipment - Operation Supplies and Expenses							
128	5016	Distribution Station Equipment - Operation Labour							
129	5017	Distribution Station Equipment - Operation Supplies and Expenses							
130	5020	Overhead Distribution Lines and Feeders - Operation Labour							
131	5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses							
132	5030	Overhead Subtransmission Feeders - Operation							
133	5035	Overhead Distribution Transformers- Operation							
134	5040	Underground Distribution Lines and Feeders - Operation Labour							
135	5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses							
136	5050	Underground Subtransmission Feeders - Operation							
137	5055	Underground Distribution Transformers - Operation							
138	5065	Meter Expense							

	A	B	C	D	E	F	BZ	CN	CO
18	USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Street Light	Total - A&G	
139	5070	Customer Premises - Operation Labour							[redacted]
140	5075	Customer Premises - Materials and Expenses							[redacted]
141	5085	Miscellaneous Distribution Expense							[redacted]
142	5090	Underground Distribution Lines and Feeders - Rental Paid							[redacted]
143	5095	Overhead Distribution Lines and Feeders - Rental Paid							[redacted]
144	5096	Other Rent							[redacted]
145	5105	Maintenance Supervision and Engineering							[redacted]
146	5110	Maintenance of Buildings and Fixtures - Distribution Stations							[redacted]
147	5112	Maintenance of Transformer Station Equipment							[redacted]
148	5114	Maintenance of Distribution Station Equipment							[redacted]
149	5120	Maintenance of Poles, Towers and Fixtures							[redacted]
150	5125	Maintenance of Overhead Conductors and Devices							[redacted]
151	5130	Maintenance of Overhead Services							[redacted]
152	5135	Overhead Distribution Lines and Feeders - Right of Way							
153	5145	Maintenance of Underground Conduit							[redacted]
154	5150	Maintenance of Underground Conductors and Devices							[redacted]
155	5155	Maintenance of Underground Services							
156	5160	Maintenance of Line Transformers							[redacted]
157	5175	Maintenance of Meters							[redacted]
158	5305	Supervision							[redacted]
159	5310	Meter Reading Expense							[redacted]
160	5315	Customer Billing							[redacted]
161	5320	Collecting							[redacted]
162	5325	Collecting - Cash Over and Short							[redacted]
163	5330	Collection Charges							[redacted]
164	5335	Bad Debt Expense							[redacted]
165	5340	Miscellaneous Customer Accounts Expenses							[redacted]
166	5405	Supervision							[redacted]
167	5410	Community Relations - Sundry							[redacted]
168	5415	Energy Conservation							[redacted]
169	5420	Community Safety Program							[redacted]
170	5425	Miscellaneous Customer Service and Informational Expenses							[redacted]
171	5505	Supervision							[redacted]
172	5510	Demonstrating and Selling Expense							[redacted]
173	5515	Advertising Expense							[redacted]
174	5520	Miscellaneous Sales Expense							[redacted]
175	5605	Executive Salaries and Expenses							[redacted]
176	5610	Management Salaries and Expenses							[redacted]
177	5615	General Administrative Salaries and Expenses							[redacted]
178	5620	Office Supplies and Expenses							[redacted]
179	5625	Administrative Expense Transferred Credit							[redacted]
180	5630	Outside Services Employed							[redacted]
181	5635	Property Insurance							[redacted]
182	5640	Injuries and Damages							[redacted]
183	5645	Employee Pensions and Benefits							[redacted]
184	5650	Franchise Requirements							[redacted]
185	5655	Regulatory Expenses							[redacted]
186	5660	General Advertising Expenses							[redacted]
187	5665	Miscellaneous General Expenses							[redacted]
188	5670	Rent							[redacted]
189	5675	Maintenance of General Plant							[redacted]
190	5680	Electrical Safety Authority Fees							[redacted]
191	5685	Independent Market Operator Fees and Penalties							[redacted]
192	5705	Amortization Expense - Property, Plant, and Equipment							
193	5710	Amortization of Limited Term Electric Plant							[redacted]
194	5715	Amortization of Intangibles and Other Electric Plant							[redacted]
195	5720	Amortization of Electric Plant Acquisition Adjustments							[redacted]

Row	Account	Description	Demand Allocators: Demand Total	1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	Customer Total	Customer Allocators: 1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	Total
183	5065	Meter Expense																	
184	5070	Customer Premises - Operation Labour																	
185	5075	Customer Premises - Materials and Expenses																	
186	5085	Miscellaneous Distribution Expense																	
187	5090	Underground Distribution Lines and Feeders - Rental Paid																	
188	5095	Overhead Distribution Lines and Feeders - Rental Paid																	
189	5096	Other Rent																	
190	5105	Maintenance Supervision and Engineering																	
191	5110	Maintenance of Buildings and Fixtures - Distribution Stations																	
192	5112	Maintenance of Transformer Station Equipment																	
193	5114	Maintenance of Distribution Station Equipment																	
194	5120	Maintenance of Poles, Towers and Fixtures																	
195	5125	Maintenance of Overhead Conductors and Devices																	
196	5130	Maintenance of Overhead Services																	
197	5135	Overhead Distribution Lines and Feeders - Right of Way																	
198	5145	Maintenance of Underground Conduit																	
199	5150	Maintenance of Underground Conductors and Devices																	
200	5155	Maintenance of Underground Services																	
201	5160	Maintenance of Line Transformers																	
202	5175	Maintenance of Meters																	
203	5305	Supervision																	
204	5310	Meter Reading Expense																	
205	5315	Customer Billing																	
206	5320	Collecting																	
207	5325	Collecting- Cash Over and Short																	
208	5330	Collection Charges																	
209	5335	Bad Debt Expense																	
210	5340	Miscellaneous Customer Accounts Expenses																	
211	5405	Supervision																	
212	5410	Community Relations - Sundry																	
213	5415	Energy Conservation																	
214	5420	Community Safety Program																	
215	5425	Miscellaneous Customer Service and Informational Expenses																	
216	5505	Supervision																	
217	5510	Demonstrating and Selling Expense																	
218	5515	Advertising Expense																	
219	5520	Miscellaneous Sales Expense																	
220	5605	Executive Salaries and Expenses																	
221	5610	Management Salaries and Expenses																	
222	5615	General Administrative Salaries and Expenses																	
223	5620	Office Supplies and Expenses																	
224	5625	Administrative Expense Transferred Credit																	
225	5630	Outside Services Employed																	
226	5635	Property Insurance																	
227	5640	Injuries and Damages																	
228	5645	Employee Pensions and Benefits																	
229	5650	Franchise Requirements																	
230	5655	Regulatory Expenses																	
231	5660	General Advertising Expenses																	
232	5665	Miscellaneous General Expenses																	
233	5670	Rent																	
234	5675	Maintenance of General Plant																	
235	5680	Electrical Safety Authority Fees																	
236	6105	Taxes Other Than Income Taxes																	
237	6205	Donations																	
238	6210	Life Insurance																	
239	6215	Penalties																	
240	6225	Other Deductions																	
242		OM&A Expenses	$33,895,289	$14,376,696	$222,617	$5,029,520	$7,750,546	$4,821,210	$1,035,259	$659,440	$33,895,289								

Row	Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)	Demand Allocators: Demand Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Customer Total	Customer Allocators: Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Total
250	1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
251	1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252	1820	$ 1,753,022	$ 372,057	$ 862	$ 175,526	$ 566,672	$ 451,246	$ 180,305	$ 6,355	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
253	1830	$ 134	$ 31	$ 0	$ 14	$ 46	$ 33	$ 10	$ 1	$ 68	$ 59	$ 1	$ 6	$ 1	$ 0	$ 0	$ 4	$ -
254	1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
255	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256	1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
257	1850	$ 1,826,543	$ 488,885	$ 1,056	$ 230,344	$ 720,444	$ 377,660	$ -	$ 8,153	$ 739,054	$ 644,758	$ 13,160	$ 65,525	$ 15,610	$ 1,079	$ -	$ 42,671	$ -
258	1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,499,147	$ 652,025	$ 25,617	$ 662,641	$ 157,864	$ 10,915	$ -	$ 43,152	$ -
259	1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 185	$ 68	$ 0	$ 65	$ 62	$ 9	$ 0	$ -	$ -
260	1815-1855	$ 3,741,465	$ 880,848	$ 1,973	$ 415,310	$ 1,320,893	$ 863,784	$ 223,777	$ 14,880	$ 1,904,901	$ 1,563,890	$ 33,849	$ 246,579	$ 60,582	$ 5,759	$ 508	$ 103,468	$ -
261	1830 & 1835	$ 212,140	$ 48,334	$ 109	$ 22,753	$ 72,826	$ 51,582	$ 15,676	$ 819	$ 107,785	$ 83,927	$ 1,917	$ 9,600	$ 2,343	$ 223	$ 4	$ 8,216	$ -
262	1840 & 1845	$ 1,013,180	$ 240,298	$ 537	$ 113,294	$ 359,963	$ 237,712	$ 57,320	$ 4,056	$ 514,853	$ 448,773	$ 9,160	$ 45,836	$ 11,116	$ 990	$ 14	$ 29,700	$ -
263	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
264	BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 761,732	$ 419,461	$ -	$ 190,607	$ 151,663	$ 197,153	$ -	$ -	$ -
265	Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
266	CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 830,046	$ 722,995	$ 14,757	$ 74,056	$ 18,238	$ 1,911	$ 42	$ 47,849	$ -
267	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
268	CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
269	CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270	CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271	CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
272	CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 516,346	$ 180,615	$ 386	$ 171,451	$ 163,894	$ 23,302	$ 1,107	$ -	$ -
273	CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274	CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 149,327	-$ 55,857	-$ 468	-$ 74,018	-$ 18,884	-$ 2,033	-$ 89	-$ 1	$ -
275	DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276	LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
277	LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
278	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
279	NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	A	B	C	D	E	F
9	**Categorization and Allocation of Contributed Capital**					
10	**Contributed Capital - 1995**					
14						
15						
16						
17	**Account**	**Description**	**Contributed Capital**	**Demand**	**Customer**	**Total**
367						
368	**Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710**					
369						
370						
371						
372						
373	**Account**	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**
374	1565	Conservation and Demand Management	$0	$0	$0	$0
375	1805	Land	$0	$0	$0	$0
376	1805-1	Land Station >50 kV	$0	$0	$0	$0
377	1805-2	Land Station <50 kV	$0	$0	$0	$0
378	1806	Land Rights	$0	$0	$0	$0
379	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0
380	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0
381	1808	Buildings and Fixtures	$0	$0	$0	$0
382	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0
383	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0
384	1810	Leasehold Improvements	$0	$0	$0	$0
385	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0
386	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0
387	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0
388	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0
389	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0
390	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0
391	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0
392	1825	Storage Battery Equipment	$0	$0	$0	$0
393	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0
394	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0
395	1830	Poles, Towers and Fixtures	$0	$0	$0	$0
396	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0
397	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0
398	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0
399	1835	Overhead Conductors and Devices	$0	$0	$0	$0
400	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0
401	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0
402	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0
403	1840	Underground Conduit	$0	$0	$0	$0
404	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0
405	1840-4	Underground Conduit - Primary	$0	$0	$0	$0
406	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0
407	1845	Underground Conductors and Devices	$0	$0	$0	$0
408	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0
409	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0
410	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0
411	1850	Line Transformers	$0	$0	$0	$0
412	1855	Services	$0	$0	$0	$0
413	1860	Meters	$0	$0	$0	$0
414		**Sub - Total**	$0	$0	$0	$0
415	**General Plant**					
416	1905	Land	$0			
417	1906	Land Rights	$0			
418	1908	Buildings and Fixtures	$0			
419	1910	Leasehold Improvements	$0			
420	1915	Office Furniture and Equipment	$0			
421	1920	Computer Equipment - Hardware	$0			
422	1925	Computer Software	$0			
423	1930	Transportation Equipment	$0			
424	1935	Stores Equipment	$0			
425	1940	Tools, Shop and Garage Equipment	$0			
426	1945	Measurement and Testing Equipment	$0			
427	1950	Power Operated Equipment	$0			
428	1955	Communication Equipment	$0			
429	1960	Miscellaneous Equipment	$0			
430	1970	Load Management Controls - Customer Premises	$0			
431	1975	Load Management Controls - Utility Premises	$0			
432	1980	System Supervisory Equipment	$0			
433	1990	Other Tangible Property	$0			
434	2005	Property Under Capital Leases	$0			
435	2010	Electric Plant Purchased or Sold	$0			
436		**Sub - Total**	$0			
437						
438		**TOTAL - 5710**	$0	$0	$0	$0

Categorization and Allocation of Contributed Capital

Contributed Capital - 1995

Account	Description	Contributed Capital	Demand	Customer	Total

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 6715

Account	Description	Depreciation	Demand	Customer	Total
1565	Conservation and Demand Management	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0
General Plant					
1905	Land	$0			
1906	Land Rights	$0			
1908	Buildings and Fixtures	$0			
1910	Leasehold Improvements	$0			
1915	Office Furniture and Equipment	$0			
1920	Computer Equipment - Hardware	$0			
1925	Computer Software	$0			
1930	Transportation Equipment	$0			
1935	Stores Equipment	$0			
1940	Tools, Shop and Garage Equipment	$0			
1945	Measurement and Testing Equipment	$0			
1950	Power Operated Equipment	$0			
1955	Communication Equipment	$0			
1960	Miscellaneous Equipment	$0			
1970	Load Management Controls - Customer Premises	$0			
1975	Load Management Controls - Utility Premises	$0			
1980	System Supervisory Equipment	$0			
1990	Other Tangible Property	$0			
2005	Property Under Capital Leases	$0			
2010	Electric Plant Purchased or Sold	$0			
	Sub - Total	$0			
	TOTAL - 5715	$0	$0	$0	$0

9 Categorization and Allocation of Contributed Capital

10 Contributed Capital - 1995

Row	Account	Description	Contributed Capital	Demand	Customer	Total
17						

514 Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipr

Row	Account	Description	Depreciation	Demand	Customer	Total
520	1565	Conservation and Demand Management	$0	$0	$0	$0
521	1805	Land	$0	$0	$0	$0
522	1805-1	Land Station >50 kV	$0	$0	$0	$0
523	1805-2	Land Station <50 kV	$0	$0	$0	$0
524	1806	Land Rights	$0	$0	$0	$0
525	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0
526	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0
527	1808	Buildings and Fixtures	$0	$0	$0	$0
528	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0
529	1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0
530	1810	Leasehold Improvements	$0	$0	$0	$0
531	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0
532	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0
533	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0
534	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0
535	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0
536	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0
537	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0
538	1825	Storage Battery Equipment	$0	$0	$0	$0
539	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0
540	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0
541	1830	Poles, Towers and Fixtures	$0	$0	$0	$0
542	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0
543	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0
544	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0
545	1835	Overhead Conductors and Devices	$0	$0	$0	$0
546	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0
547	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0
548	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0
549	1840	Underground Conduit	$0	$0	$0	$0
550	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0
551	1840-4	Underground Conduit - Primary	$0	$0	$0	$0
552	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0
553	1845	Underground Conductors and Devices	$0	$0	$0	$0
554	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0
555	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0
556	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0
557	1850	Line Transformers	$0	$0	$0	$0
558	1855	Services	$0	$0	$0	$0
559	1860	Meters	$0	$0	$0	$0
560		Sub - Total	$0	$0	$0	$0
561	General Plant					
562	1905	Land	$0			
563	1906	Land Rights	$0			
564	1908	Buildings and Fixtures	$0			
565	1910	Leasehold Improvements	$0			
566	1915	Office Furniture and Equipment	$0			
567	1920	Computer Equipment - Hardware	$0			
568	1925	Computer Software	$0			
569	1930	Transportation Equipment	$0			
570	1935	Stores Equipment	$0			
571	1940	Tools, Shop and Garage Equipment	$0			
572	1945	Measurement and Testing Equipment	$0			
573	1950	Power Operated Equipment	$0			
574	1955	Communication Equipment	$0			
575	1960	Miscellaneous Equipment	$0			
576	1970	Load Management Controls - Customer Premises	$0			
577	1975	Load Management Controls - Utility Premises	$0			
578	1980	System Supervisory Equipment	$0			
579	1990	Other Tangible Property	$0			
580	2005	Property Under Capital Leases	$0			
581	2010	Electric Plant Purchased or Sold	$0			
582		Sub - Total	$0			
583						
584		TOTAL - 5720	$0	$0	$0	$0

A	B	C	D	E	F
Categorization and Allocation of Contributed Capital					
Contributed Capital - 1995					
Account	**Description**	**Contributed Capital**	**Demand**	**Customer**	**Total**
Account	**Description**		**Demand**	**Customer**	**Total**
1565	Conservation and Demand Management	100%	0%	100%	100%
1805	Land				
1805-1	Land Station >50 kV	100%	100%	0%	100%
1805-2	Land Station <50 kV	100%	100%	0%	100%
1806	Land Rights				
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%
1808	Buildings and Fixtures				
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%
1810	Leasehold Improvements				
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%
1820	Distribution Station Equipment - Normally Primary below 50 kV				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%
1825	Storage Battery Equipment				
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%
1830	Poles, Towers and Fixtures				
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%
1835	Overhead Conductors and Devices				
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%
1840	Underground Conduit				
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%
1840-4	Underground Conduit - Primary	100%	65%	35%	100%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%
1845	Underground Conductors and Devices				
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%
1850	Line Transformers	100%	70%	30%	100%
1855	Services	100%	0%	100%	100%
1860	Meters	100%	0%	100%	100%
General Plant					
1905	Land	100%			
1906	Land Rights	100%			
1908	Buildings and Fixtures	100%			
1910	Leasehold Improvements	100%			
1915	Office Furniture and Equipment	100%			
1920	Computer Equipment - Hardware	100%			
1925	Computer Software	100%			
1930	Transportation Equipment	100%			
1935	Stores Equipment	100%			
1940	Tools, Shop and Garage Equipment	100%			
1945	Measurement and Testing Equipment	100%			
1950	Power Operated Equipment	100%			
1955	Communication Equipment	100%			
1960	Miscellaneous Equipment	100%			
1970	Load Management Controls - Customer Premises	100%			
1975	Load Management Controls - Utility Premises	100%			
1980	System Supervisory Equipment	100%			
1990	Other Tangible Property	100%			
2005	Property Under Capital Leases	100%			
2010	Electric Plant Purchased or Sold	100%			

Categorization and Allocation of Contribute
Contributed Capital - 1995

Account	Description	Demand Allocation 1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	Sub -total Total

Categorization and Allocation of Amortizati

Account	Description	Demand Allocation 1 Residential	2 Small Commercial	3 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	Sub -total Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0
1605	Land	$0	$0	$0	$0	$0	$0	$0	$0
1605-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1605-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1606	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
1606-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1606-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1608	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1608-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1608-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0
1610	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
1610-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1610-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1615	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1620	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1620-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0
1620-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0
1620-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0
1625	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0
1625-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1625-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
1630	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1630-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1630-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0
1630-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1635	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1635-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1635-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
1635-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1640	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
1640-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1640-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0
1640-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1645	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1645-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1645-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
1645-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
1650	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
1655	Services	$0	$0	$0	$0	$0	$0	$0	$0
1660	Meters	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0
General Plant									
1905	Land								
1906	Land Rights								
1908	Buildings and Fixtures								
1910	Leasehold Improvements								
1915	Office Furniture and Equipment								
1920	Computer Equipment - Hardware								
1925	Computer Software								
1930	Transportation Equipment								
1935	Stores Equipment								
1940	Tools, Shop and Garage Equipment								
1945	Measurement and Testing Equipment								
1950	Power Operated Equipment								
1955	Communication Equipment								
1960	Miscellaneous Equipment								
1970	Load Management Controls - Customer Premises								
1975	Load Management Controls - Utility Premises								
1980	System Supervisory Equipment								
1990	Other Tangible Property								
2005	Property Under Capital Leases								
2010	Electric Plant Purchased or Sold								
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$0	$0	$0	$0	$0	$0	$0	$0

	A	B	G	H	I	J	K	L	M	AA
9	Categorization and Allocation of Contribute									
10	Contributed Capital - 1995									
14										
15			Demand Allocation							
16			1	2	3	4	5	6	7	Sub-total
17	Account	Description	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Total
438										
440										
441	Categorization and Allocation of Accumula									
442										
443										
444			Demand Allocation							
445			1	2	3	4	5	6	7	Sub-total
446	Account	Description	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Sub-total
447	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0
448	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0
449	1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
450	1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
451	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
452	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
453	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
454	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
455	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
456	1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
457	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
458	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
459	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
460	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
461	1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
462	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0
463	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0
464	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0
465	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0
466	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
467	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
468	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
469	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
470	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0
471	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
472	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
473	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
474	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
475	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
476	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
477	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
478	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0
479	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
480	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
481	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
482	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
483	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
484	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
485	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0
486	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0
487		Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0
488	General Plant									
489	1905	Land								
490	1906	Land Rights								
491	1908	Buildings and Fixtures								
492	1910	Leasehold Improvements								
493	1915	Office Furniture and Equipment								
494	1920	Computer Equipment - Hardware								
495	1925	Computer Software								
496	1930	Transportation Equipment								
497	1935	Stores Equipment								
498	1940	Tools, Shop and Garage Equipment								
499	1945	Measurement and Testing Equipment								
500	1950	Power Operated Equipment								
501	1955	Communication Equipment								
502	1960	Miscellaneous Equipment								
503	1970	Load Management Controls - Customer Premises								
504	1975	Load Management Controls - Utility Premises								
505	1980	System Supervisory Equipment								
506	1990	Other Tangible Property								
507	2005	Property Under Capital Leases								
508	2010	Electric Plant Purchased or Sold								
509		Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0
510										
511		TOTAL 5715	$0	$0	$0	$0	$0	$0	$0	$0

	A	B	G	H	I	J	K	L	M	AA
9	Categorization and Allocation of Contribute									
10	Contributed Capital - 1995									
14										
15			Demand Allocation							
16			1	2	3	4	5	6	7	Sub-total
17	Account	Description	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Total
512										
513										
514	Categorization and Allocation of Accum. Amort - 5720									
515										
516										
517			Demand Allocation							
518			1	2	3	4	5	6	7	Sub-total
519	Account	Description	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Sub-total
520	1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0
521	1805	Land	$0	$0	$0	$0	$0	$0	$0	$0
522	1805-1	Land Station >50kV	$0	$0	$0	$0	$0	$0	$0	$0
523	1805-2	Land Station <50kV	$0	$0	$0	$0	$0	$0	$0	$0
524	1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
525	1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
526	1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
527	1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
528	1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
529	1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
530	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0
531	1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0
532	1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
533	1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
534	1820	Distribution Station Equipment - Normally Primary below 50kV	$0	$0	$0	$0	$0	$0	$0	$0
535	1820-1	Distribution Station Equipment - Normally Primary below 50kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0
536	1820-2	Distribution Station Equipment - Normally Primary below 50kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0
537	1820-3	Distribution Station Equipment - Normally Primary below 50kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0
538	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0
539	1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0
540	1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
541	1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
542	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
543	1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0
544	1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
545	1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
546	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
547	1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
548	1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
549	1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
550	1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
551	1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0
552	1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
553	1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
554	1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
555	1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0
556	1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0
557	1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
558	1855	Services	$0	$0	$0	$0	$0	$0	$0	$0
559	1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0
560		Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0
561	General Plant									
562	1905	Land								
563	1906	Land Rights								
564	1908	Buildings and Fixtures								
565	1910	Leasehold Improvements								
566	1915	Office Furniture and Equipment								
567	1920	Computer Equipment - Hardware								
568	1925	Computer Software								
569	1930	Transportation Equipment								
570	1935	Stores Equipment								
571	1940	Tools, Shop and Garage Equipment								
572	1945	Measurement and Testing Equipment								
573	1950	Power Operated Equipment								
574	1955	Communication Equipment								
575	1960	Miscellaneous Equipment								
576	1970	Load Management Controls - Customer Premises								
577	1975	Load Management Controls - Utility Premises								
578	1980	System Supervisory Equipment								
579	1990	Other Tangible Property								
580	2005	Property Under Capital Leases								
581	2010	Electric Plant Purchased or Sold								
582		Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0
583										
584		TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

Row	Account	Description	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Total
	A	B	G	H	I	J	K	L	M	AR
15			Demand Allocation							
16			1	2	3	4	5	6	7	Sub -total
586			Demand Allocation							
587			1	2	3	4	5	6	7	Sub -total
588	Account	Description	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Sub -total
589	1565	Conservation and Demand Management	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
590	1805	Land	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
591	1805-1	Land Station >50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
592	1805-2	Land Station <50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
593	1806	Land Rights	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
594	1806-1	Land Rights Station >50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
595	1806-2	Land Rights Station <50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
596	1808	Buildings and Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
597	1808-1	Buildings and Fixtures > 50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
598	1808-2	Buildings and Fixtures < 50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
599	1810	Leasehold Improvements	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
600	1810-1	Leasehold Improvements >50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
601	1810-2	Leasehold Improvements <50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
602	1815	Transformer Station Equipment - Normally Primary above 50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
603	1820	Distribution Station Equipment - Normally Primary below 50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
604	1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
605	1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	21.22%	0.05%	10.01%	32.32%	25.74%	10.29%	0.36%	100.00%
606	1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
607	1825	Storage Battery Equipment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
608	1825-1	Storage Battery Equipment > 50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
609	1825-2	Storage Battery Equipment <50 kV	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
610	1830	Poles, Towers and Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
611	1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
612	1830-4	Poles, Towers and Fixtures - Primary	21.22%	0.05%	10.01%	32.32%	25.74%	10.29%	0.36%	100.00%
613	1830-5	Poles, Towers and Fixtures - Secondary	26.77%	0.06%	12.61%	39.44%	20.66%	0.00%	0.45%	100.00%
614	1835	Overhead Conductors and Devices	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
615	1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
616	1835-4	Overhead Conductors and Devices - Primary	21.22%	0.05%	10.01%	32.32%	25.74%	10.29%	0.36%	100.00%
617	1835-5	Overhead Conductors and Devices - Secondary	26.77%	0.06%	12.61%	39.44%	20.66%	0.00%	0.45%	100.00%
618	1840	Underground Conduit	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
619	1840-3	Underground Conduit - Bulk Delivery	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
620	1840-4	Underground Conduit - Primary	21.22%	0.05%	10.01%	32.32%	25.74%	10.29%	0.36%	100.00%
621	1840-5	Underground Conduit - Secondary	26.77%	0.06%	12.61%	39.44%	20.66%	0.00%	0.45%	100.00%
622	1845	Underground Conductors and Devices	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
623	1845-3	Underground Conductors and Devices - Bulk Delivery	21.96%	0.13%	9.94%	32.65%	25.54%	9.40%	0.18%	100.00%
624	1845-4	Underground Conductors and Devices - Primary	21.22%	0.05%	10.01%	32.32%	25.74%	10.29%	0.36%	100.00%
625	1845-5	Underground Conductors and Devices - Secondary	26.77%	0.06%	12.61%	39.44%	20.66%	0.00%	0.45%	100.00%
626	1850	Line Transformers	26.77%	0.06%	12.61%	39.44%	20.66%	0.00%	0.45%	100.00%
627	1855	Services	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
628	1860	Meters	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
629	General Plant									
630	1905	Land								
631	1906	Land Rights								
632	1908	Buildings and Fixtures								
633	1910	Leasehold Improvements								
634	1915	Office Furniture and Equipment								
635	1920	Computer Equipment - Hardware								
636	1925	Computer Software								
637	1930	Transportation Equipment								
638	1935	Stores Equipment								
639	1940	Tools, Shop and Garage Equipment								
640	1945	Measurement and Testing Equipment								
641	1950	Power Operated Equipment								
642	1955	Communication Equipment								
643	1960	Miscellaneous Equipment								
644	1970	Load Management Controls - Customer Premises								
645	1975	Load Management Controls - Utility Premises								
646	1980	System Supervisory Equipment								
647	1990	Other Tangible Property								
648	2005	Property Under Capital Leases								
649	2010	Electric Plant Purchased or Sold								

Density of Utility

Density	Number of Customers	kM of Lines
74	175316	2366

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	35%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	35%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	35%
1835	Overhead Conductors and Devices	DNCP	CCA	35%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	35%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	35%
1840	Underground Conduit	DNCP	CCA	35%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	35%
1840-5	Underground Conduit - Secondary	SNCP	CCS	35%
1845	Underground Conductors and Devices	DNCP	CCA	35%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	35%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	35%
1850	Line Transformers	LTNCP	CCLT	30%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%

1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5010	Load Dispatching	1815-1855 D	1815-1855 C	35%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	35%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	35%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers-Operation	1850 D	1850 C	30%
5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	35%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	35%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	30%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	35%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	35%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	35%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	35%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	35%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	35%
5145	Maintenance of Underground Conduit	1840 D	1840 C	35%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	35%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	30%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2006 COST ALLOCATION INFORMATION FILING

Enersource Hydro Mississauga

EB-2005-0360 EB-2006-0247

Monday, January 15, 2007

Sheet E2 Allocator Worksheet - First Run

Details:
The worksheet below details how allocators are derived.

			1	2	3	4	5	6	7
Explanation	ID and Factors	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
Demand Allocators									
1 cp									
Transformation CP	TCP1	100.00%	23.44%	0.09%	10.63%	33.11%	24.25%	8.47%	0.00%
Bulk Delivery (SubTransmission) CP	BCP1	100.00%	23.44%	0.09%	10.63%	33.11%	24.25%	8.47%	0.00%
Distribution CP (Total System)	DCP1	100.00%	23.44%	0.09%	10.63%	33.11%	24.25%	8.47%	0.00%
4 cp									
Transformation CP	TCP4	100.00%	22.10%	0.10%	10.04%	32.95%	25.78%	9.02%	0.00%
Bulk Delivery (SubTransmission) CP	BCP4	100.00%	22.10%	0.10%	10.04%	32.95%	25.78%	9.02%	0.00%
Distribution CP (Total System)	DCP4	100.00%	22.10%	0.10%	10.04%	32.95%	25.78%	9.02%	0.00%
12 cp									
Transformation CP	TCP12	100.00%	21.96%	0.13%	9.94%	32.85%	25.54%	9.40%	0.18%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	21.96%	0.13%	9.94%	32.85%	25.54%	9.40%	0.18%
Distribution CP (Total System)	DCP12	100.00%	21.96%	0.13%	9.94%	32.85%	25.54%	9.40%	0.18%
NON CO_INCIDENT PEAK									
1 NCP									
Distribution NCP (Total System)	DNCP1	100.00%	25.88%	0.06%	10.02%	30.32%	23.99%	9.40%	0.33%
Primary NCP	PNCP1	100.00%	22.82%	0.06%	10.07%	31.69%	25.15%	9.86%	0.35%
Line Transformer NCP	LTNCP1	100.00%	28.56%	0.07%	12.57%	38.34%	20.03%	0.00%	0.43%
Secondary NCP	SNCP1	100.00%	28.56%	0.07%	12.57%	38.34%	20.03%	0.00%	0.43%
4 NCP									
Distribution NCP (Total System)	DNCP4	100.00%	24.54%	0.05%	9.97%	30.84%	24.48%	9.78%	0.35%
Primary NCP	PNCP4	100.00%	21.22%	0.05%	10.01%	32.32%	25.74%	10.29%	0.36%
Line Transformer NCP	LTNCP4	100.00%	26.77%	0.06%	12.61%	39.44%	20.68%	0.00%	0.45%
Secondary NCP	SNCP4	100.00%	26.77%	0.06%	12.61%	39.44%	20.68%	0.00%	0.45%
12 NCP									
Distribution NCP (Total System)	DNCP12	100.00%	23.32%	0.03%	9.89%	31.39%	24.91%	10.09%	0.36%
Primary NCP	PNCP12	100.00%	19.62%	0.03%	9.94%	33.04%	26.31%	10.66%	0.38%
Line Transformer NCP	LTNCP12	100.00%	24.91%	0.04%	12.62%	40.65%	21.31%	0.00%	0.47%
Secondary NCP	SNCP12	100.00%	24.91%	0.04%	12.62%	40.65%	21.31%	0.00%	0.47%
Demand Allocators - Composite									
DEMAND 1815-1855	1815-1855 D	100.00%	23.54%	0.05%	11.10%	35.30%	23.62%	5.98%	0.40%

	A	B	C	D	E	F	G	H	I	J
56	DEMAND 1808	1808 D	100.00%	21.96%	0.13%	9.94%	32.85%	25.54%	9.40%	0.18%
57	DEMAND 1815	1815 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
58	DEMAND 1820	1820 D	100.00%	21.22%	0.05%	10.01%	32.33%	25.74%	10.29%	0.36%
59	DEMAND 1815 & 1820	1815 & 1820 D	100.00%	21.22%	0.05%	10.01%	32.33%	25.74%	10.29%	0.36%
60	DEMAND 1830	1830 D	100.00%	22.78%	0.05%	10.74%	34.33%	24.31%	7.39%	0.39%
61	DEMAND 1835	1835 D	100.00%	22.78%	0.05%	10.74%	34.33%	24.31%	7.39%	0.39%
62	DEMAND 1830 & 1835	1830 & 1835 D	100.00%	22.78%	0.05%	10.74%	34.33%	24.31%	7.39%	0.39%
63	DEMAND 1840	1840 D	100.00%	23.72%	0.05%	11.18%	35.53%	23.46%	5.66%	0.40%
64	DEMAND 1845	1845 D	100.00%	23.72%	0.05%	11.18%	35.53%	23.46%	5.66%	0.40%
65	DEMAND 1840 & 1845	1840 & 1845 D	100.00%	23.72%	0.05%	11.18%	35.53%	23.46%	5.66%	0.40%
66	DEMAND 1850	1850 D	100.00%	26.77%	0.06%	12.61%	39.44%	20.68%	0.00%	0.45%
67	DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
68	DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
69										
70	CUSTOMER ALLOCATORS									
71										
72	Billing Data									
73	kWh	CEN	100.00%	20.27%	0.24%	9.32%	33.06%	24.74%	11.87%	0.50%
74	kW	CDEM	100.00%	0.00%	0.00%	0.00%	49.74%	37.77%	11.67%	0.82%
75	kWh - Excl WMP	CEN EWMP	100.00%	20.27%	0.24%	9.32%	33.06%	24.74%	11.87%	0.50%
76										
77	Dollar Billed (per 2006 EDR)	CREV	100.00%	36.07%	0.91%	14.69%	29.46%	13.18%	5.22%	0.46%
78	Bad Debt 3 Year Historical Average	BDHA	100.00%	43.74%	0.00%	19.88%	15.82%	20.56%	0.00%	0.00%
79	Late Payment 3 Year Historical Average	LPHA	100.00%	41.08%	0.05%	19.43%	27.59%	11.56%	0.30%	0.00%
80										
81	Number of Bills	CNB	100.00%	80.21%	0.34%	15.16%	3.87%	0.42%	0.01%	0.00%
82	Number of Connections (Unmetered)	CCON	100.00%	0.00%	23.57%	0.00%	0.00%	0.00%	0.00%	76.43%
83										
85										
86	Total Number of Customer	CCA	100.00%	82.17%	1.68%	8.42%	2.07%	0.22%	0.00%	5.44%
87	Subtransmission Customer Base	CCB	100.00%	0.00%	23.57%	0.00%	0.00%	0.00%	0.00%	76.43%
88	Primary Feeder Customer Base	CCP	100.00%	82.17%	1.68%	8.42%	2.07%	0.22%	0.00%	5.44%
89	Line Transformer Customer Base	CCLT	100.00%	82.37%	1.68%	8.37%	1.99%	0.14%	0.00%	5.45%
90	Secondary Feeder Customer Base	CCS	100.00%	82.37%	1.68%	8.37%	1.99%	0.14%	0.00%	5.45%
91										
92	Weighted - Services	CWCS	100.00%	41.98%	1.71%	42.66%	10.16%	0.70%	0.00%	2.78%
93	Weighted Meter -Capital	CWMC	100.00%	33.40%	0.07%	31.71%	30.31%	4.31%	0.20%	0.00%
94	Weighted Meter Reading	CWMR	100.00%	70.65%	0.11%	8.71%	7.56%	11.97%	0.97%	0.04%
95	Weighted Bills	CWNB	100.00%	36.95%	0.31%	48.87%	12.47%	1.34%	0.06%	0.00%
96										
97	CUSTOMER ALLOCATORS - Composite									
98										
99	CUSTOMER 1815-1855	1815-1855 C	100.00%	77.63%	1.68%	12.24%	3.01%	0.29%	0.03%	5.14%
100	CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
101	CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
102	CUSTOMER 1820	1820 C	100.00%	20.27%	0.24%	9.32%	33.06%	24.74%	11.87%	0.50%
103	CUSTOMER 1815 & 1820	1815 & 1820 C	100.00%	20.27%	0.24%	9.32%	33.06%	24.74%	11.87%	0.50%
104	CUSTOMER 1830	1830 C	100.00%	82.23%	1.68%	8.40%	2.05%	0.19%	0.00%	5.44%
105	CUSTOMER 1835	1835 C	100.00%	82.23%	1.68%	8.40%	2.05%	0.19%	0.00%	5.44%
106	CUSTOMER 1830 & 1835	1830 & 1835 C	100.00%	82.23%	1.68%	8.40%	2.05%	0.19%	0.00%	5.44%
107	CUSTOMER 1840	1840 C	100.00%	82.26%	1.68%	8.40%	2.04%	0.18%	0.00%	5.44%
108	CUSTOMER 1845	1845 C	100.00%	82.26%	1.68%	8.40%	2.04%	0.18%	0.00%	5.44%

	A	B	C	D	E	F	G	H	I	J
109	CUSTOMER 1840 & 1845	1840 & 1845 C	100.00%	82.26%	1.68%	8.40%	2.04%	0.18%	0.00%	5.44%
110	CUSTOMER 1850	1850 C	100.00%	82.37%	1.68%	8.37%	1.99%	0.14%	0.00%	5.45%
111	CUSTOMER 1855	1855 C	100.00%	41.98%	1.71%	42.66%	10.16%	0.70%	0.00%	2.78%
112	CUSTOMER 1860	1860 C	100.00%	33.40%	0.07%	31.71%	30.31%	4.31%	0.20%	0.00%
113										
114	**Composite Allocators**									
115	Net Fixed Assets	NFA	100.00%	40.51%	0.59%	13.24%	24.49%	15.26%	4.05%	1.86%
116	Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	40.91%	0.59%	12.92%	24.48%	15.26%	3.96%	1.89%
117	5005-5340	O&M	100.00%	42.45%	0.66%	14.88%	22.83%	14.20%	3.03%	1.95%

	A	B	C	D	E	F	G	H	I
13	PLCC WATTS								
14	400								
15									
16			1	2	3	4	5	6	7
17	Customer Classes	Total	Residential	Small Commercial	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light
18									
19	CCA	188,288	154,721	3,158	15,848	3,903	409	9	10,240
20	CCB	13,398	0	3,158	0	0	0	0	10,240
21	CCP	188,288	154,721	3,158	15,848	3,903	409	9	10,240
22	CCLT	187,848	154,721	3,158	15,724	3,746	259	0	10,240
23	CCS	187,848	154,721	3,158	15,724	3,746	259	0	10,240
24									
25	PLCC-CCA	75,315	61,888	1,263	6,339	1,561	164	4	4,096
26	PLCC-CCB	5,359	0	1,263	0	0	0	0	4,096
27	PLCC-CCP	75,315	61,888	1,263	6,339	1,561	164	4	4,096
28	PLCC-CCLT	75,139	61,888	1,263	6,290	1,498	104	0	4,096
29	PLCC-CCS	75,139	61,888	1,263	6,290	1,498	104	0	4,096
30									
31									
32	1NCP								
33	DNCP1	1,512,734	390,149	2,118	151,023	457,013	361,648	141,648	9,135
34	PNCP1	1,505,957	388,402	2,109	150,346	454,965	360,028	141,013	9,094
35	LTNCP1	1,167,673	373,967	2,030	143,621	420,356	218,943	0	8,756
36	SNCP1	1,167,673	373,967	2,030	143,621	420,356	218,943	0	8,756
37									
38	PLCC - 1NCP								
39	DNCP1A	1,507,375	390,149	855	151,023	457,013	361,648	141,648	5,039
40	PNCP1A	1,430,642	326,513	846	144,007	453,404	359,865	141,010	4,998
41	LTNCP1A	1,092,534	312,078	767	137,331	418,858	218,840	0	4,660
42	SNCP1A	1,092,534	312,078	767	137,331	418,858	218,840	0	4,660
43									
44	4 NCP								
45									
46	DNCP4	5,726,970	1,399,878	7,737	568,601	1,759,689	1,396,954	557,979	36,132
47	PNCP4	5,701,314	1,393,607	7,703	566,054	1,751,806	1,390,696	555,479	35,970
48	LTNCP4	4,388,861	1,341,813	7,416	540,733	1,618,546	845,721	0	34,633
49	SNCP4	4,388,861	1,341,813	7,416	540,733	1,618,546	845,721	0	34,633
50									
51	PLCC - 4NCP								
52	DNCP4A	5,705,534	1,399,878	2,685	568,601	1,759,689	1,396,954	557,979	19,748
53	PNCP4A	5,400,054	1,146,053	2,650	540,697	1,745,561	1,390,041	555,465	19,586
54	LTNCP4A	4,088,305	1,094,259	2,364	515,574	1,612,552	845,306	0	18,249
55	SNCP4A	4,088,305	1,094,259	2,364	515,574	1,612,552	845,306	0	18,249
56									
57	12NCP								
58									
59	DNCP12	15,777,148	3,663,721	20,320	1,554,572	4,932,299	3,914,751	1,585,225	106,259
60	PNCP12	15,706,469	3,647,308	20,229	1,547,607	4,910,203	3,897,213	1,578,124	105,783
61	LTNCP12	12,018,149	3,511,755	19,477	1,478,378	4,536,683	2,370,004	0	101,852
62	SNCP12	12,018,149	3,511,755	19,477	1,478,378	4,536,683	2,370,004	0	101,852
63									
64	PLCC - 12NCP								
65	DNCP12A	15,712,839	3,663,721	5,162	1,554,572	4,932,299	3,914,751	1,585,225	57,109
66	PNCP12A	14,802,688	2,904,648	5,071	1,471,537	4,891,469	3,895,250	1,578,081	56,633
67	LTNCP12A	11,116,480	2,769,094	4,319	1,402,903	4,518,702	2,368,760	0	52,701
68	SNCP12A	11,116,480	2,769,094	4,319	1,402,903	4,518,702	2,368,760	0	52,701

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1555	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC					
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC					
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC					
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC					
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC					
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC					

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
3046	Balance Transferred From Income	Equity	NI								NFA				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB				
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA				
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA				
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA				
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA				
4225	Late Payment Charges	Late Payment Charges	mi								LPHA				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA				
4305	Regulatory Debits	Other Income & Deductions	mi								NFA				
4310	Regulatory Credits	Other Income & Deductions	mi								NFA				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA				
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN					
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP					
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN					
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	830 & 1835	830 & 1835	1830 & 1835	x	830 & 1835	1830 & 1835 C					1830 & 1835	1830 & 1835 D

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835 C		830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845 C		840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC						
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA						
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA						
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845	840 & 1845	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M					
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C					1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C					1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835	830 & 1835	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C					1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C					1845 D	1845 D

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
5105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
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6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

Ontario

2006 COST ALLOCATION INFORMATION FILING
Enersource Hydro Mississauga
EB-2005-0360 EB-2006-0247
Monday, January 15, 2007
Sheet E5 Reconciliation Worksheet - First Run

Details:
The worksheet below shows reconciliation of costs included and excluded in the Trial Balance.

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS
1565	Conservation and Demand Management Expenditures and Recoveries				
1608	Franchises and Consents				
1805	Land				
1805-1	Land Station >50 kV				
1805-2	Land Station <50 kV				
1806	Land Rights				
1806-1	Land Rights Station >50 kV				
1806-2	Land Rights Station <50 kV				
1808	Buildings and Fixtures				
1808-1	Buildings and Fixtures > 50 kV				
1808-2	Buildings and Fixtures < 50 KV				
1810	Leasehold Improvements				
1810-1	Leasehold Improvements >50 kV				
1810-2	Leasehold Improvements <50 kV				
1815	Transformer Station Equipment - Normally Primary above 50 kV				
1820	Distribution Station Equipment - Normally Primary below 50 kV				

1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)
1825	Storage Battery Equipment
1825-1	Storage Battery Equipment > 50 kV
1825-2	Storage Battery Equipment <50 kV
1830	Poles, Towers and Fixtures
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery
1830-4	Poles, Towers and Fixtures - Primary
1830-5	Poles, Towers and Fixtures - Secondary
1835	Overhead Conductors and Devices
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery
1835-4	Overhead Conductors and Devices - Primary
1835-5	Overhead Conductors and Devices - Secondary
1840	Underground Conduit
1840-3	Underground Conduit - Bulk Delivery
1840-4	Underground Conduit - Primary
1840-5	Underground Conduit - Secondary
1845	Underground Conductors and Devices
1845-3	Underground Conductors and Devices - Bulk Delivery
1845-4	Underground Conductors and Devices - Primary
1845-5	Underground Conductors and Devices - Secondary
1850	Line Transformers
1855	Services
1860	Meters
1905	Land
1906	Land Rights

1908	Buildings and Fixtures
1910	Leasehold Improvements
1915	Office Furniture and Equipment
1920	Computer Equipment - Hardware
1925	Computer Software
1930	Transportation Equipment
1935	Stores Equipment
1940	Tools, Shop and Garage Equipment
1945	Measurement and Testing Equipment
1950	Power Operated Equipment
1955	Communication Equipment
1960	Miscellaneous Equipment
1970	Load Management Controls - Customer Premises
1975	Load Management Controls - Utility Premises
1980	System Supervisory Equipment
1990	Other Tangible Property
1995	Contributions and Grants - Credit
2005	Property Under Capital Leases
2010	Electric Plant Purchased or Sold
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment
2120	Accumulated Amortization of Electric Utility Plant - Intangibles
3046	Balance Transferred From Income
4080	Distribution Services Revenue
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4090	Electric Services Incidental to Energy Sales
4205	Interdepartmental Rents
4210	Rent from Electric Property
4215	Other Utility Operating Income
4220	Other Electric Revenues
4225	Late Payment Charges

4235	Miscellaneous Service Revenues
4240	Provision for Rate Refunds
4245	Government Assistance Directly Credited to Income
4305	Regulatory Debits
4310	Regulatory Credits
4315	Revenues from Electric Plant Leased to Others
4320	Expenses of Electric Plant Leased to Others
4325	Revenues from Merchandise, Jobbing, Etc.
4330	Costs and Expenses of Merchandising, Jobbing, Etc.
4335	Profits and Losses from Financial Instrument Hedges
4340	Profits and Losses from Financial Instrument Investments
4345	Gains from Disposition of Future Use Utility Plant
4350	Losses from Disposition of Future Use Utility Plant
4355	Gain on Disposition of Utility and Other Property
4360	Loss on Disposition of Utility and Other Property
4365	Gains from Disposition of Allowances for Emission
4370	Losses from Disposition of Allowances for Emission
4390	Miscellaneous Non-Operating Income
4395	Rate-Payer Benefit Including Interest
4398	Foreign Exchange Gains and Losses, Including Amortization
4405	Interest and Dividend Income
4415	Equity in Earnings of Subsidiary Companies

4705	Power Purchased
4708	Charges-WMS
4710	Cost of Power Adjustments
4712	Charges-One-Time
4714	Charges-NW
4715	System Control and Load Dispatching
4716	Charges-CN
4730	Rural Rate Assistance Expense
5005	Operation Supervision and Engineering
5010	Load Dispatching
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment - Operation Labour
5017	Distribution Station Equipment - Operation Supplies and Expenses
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders - Operation
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5050	Underground Subtransmission Feeders - Operation
5055	Underground Distribution Transformers - Operation
5065	Meter Expense
5070	Customer Premises - Operation Labour

5075	Customer Premises - Materials and Expenses
5085	Miscellaneous Distribution Expense
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5096	Other Rent
5105	Maintenance Supervision and Engineering
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5130	Maintenance of Overhead Services
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5155	Maintenance of Underground Services
5160	Maintenance of Line Transformers
5175	Maintenance of Meters
5305	Supervision
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses

5405	Supervision
5410	Community Relations - Sundry
5415	Energy Conservation
5420	Community Safety Program
5425	Miscellaneous Customer Service and Informational Expenses
5505	Supervision
5510	Demonstrating and Selling Expense
5515	Advertising Expense
5520	Miscellaneous Sales Expense
5605	Executive Salaries and Expenses
5610	Management Salaries and Expenses
5615	General Administrative Salaries and Expenses
5620	Office Supplies and Expenses
5625	Administrative Expense Transferred Credit
5630	Outside Services Employed
5635	Property Insurance
5640	Injuries and Damages
5645	Employee Pensions and Benefits
5650	Franchise Requirements
5655	Regulatory Expenses
5660	General Advertising Expenses
5665	Miscellaneous General Expenses
5670	Rent
5675	Maintenance of General Plant
5680	Electrical Safety Authority Fees
5685	Independent Market Operator Fees and Penalties
5705	Amortization Expense - Property, Plant, and Equipment
5710	Amortization of Limited Term Electric Plant
5715	Amortization of Intangibles and Other Electric Plant
5720	Amortization of Electric Plant Acquisition Adjustments

Board Staff Technical Conference Question # 28

Reference: Reference: Exhibit H / Schedule 3 / Tab 1, and Exhibit H / Schedule 4 / Tab 1, Board Staff Interrogatory No. 63 (c)

Further to Board Staff Interrogatory No. 63 (c), please provide the following:

The calculated Fixed Service Charges in the table titled “Proposed Base Distribution Rates” do not match the service charges in the proposed tariff sheet in Schedule 4. For example the Residential service charge in Schedule 3 is $12.50 and in Schedule 4 it is $13.07. Is the Smart Meter rate adder at Exhibit G / Schedule 2 / Tab 7 the only source of the discrepancy between these two sources, or are there also factors related to “responsibility for the revenue requirement” as suggested in the initial response to interrogatory # 63?

Response: 28.

Customer Class	Proposed Base Fixed Service Charge, $/month (1)	Proposed 2008 Smart Meter Rate Adder, $/metered-customer/month (2)	Proposed Fixed Service Charge, $/month (3)
Residential	12.50	0.57	13.07
Small Commercial	32.41	0.57	32.98
GS < 50 kW	15.88	0.57	16.45
GS 50 – 499 kW	82.54	0.57	83.11
GS 500 – 4,999 kW	1,402.17	0.57	1,402.74
Large User	14,984.95	0.57	14,985.52
Street Lighting	0.41		0.41

(1) per Exhibit H/ Schedule 2/ Tab 1
(2) per Exhibit G/ Schedule 2/ Tab 7
(3) per Exhibit H/ Schedule 4/ Tab 1

DEFERRAL AND VARIANCE ACCOUNTS

Board Staff Technical Conference Question # 29

Reference: Board Staff Interrogatory No. 42

Why did Enersource state that the deferred OEB Costs were from January 1, 2005 to April 30, 2006 when difference between OEB costs assessments invoiced to the distributor for the Board's 2004/05 and 2005/06 (up to April 30, 2006) and OEB Costs assessments previously included in rates was allowed? There is an opening balance in Question 44 on January 1, 2005 for 1508 – OEB Costs sub-account?

Response: 29.

EHM summarizes the OEB cost assessments for January 2004 to April 2006 in the attached spreadsheet. In the 2006 EDR Decision and Order by the OEB Board (EB-2005-0360), Enersource was awarded the recovery of 2004 OEB assessed costs of $384,000 effective May 1, 2006 to April 30, 2008 through a rate rider. The Board also approved an amount representative of future OEB cost assessments within rates, effective May 1, 2006. This decision and order also noted,"…With respect to the 2005 OEB costs, the Board indicated in a December 20, 2004 letter to electricity distributors that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, the Board will review and dispose of the 2005 OEB dues at a later time".

The actual 2004 OEB cost assessments were $424,709 which reflects the opening balance on Question 44 on January 1, 2005 for 1508 – Other Regulatory Assets - Sub-Account - OEB Costs Assessments.

Enersource Hydro Mississauga
Account 1508 - OEB Costs
Reconciliation to April 30, 2006
Board TCQ #29

Invoice No.	Invoice Date	OEB Invoices	Description	Amount	Months	Deferral By Enersource Per Month	Ref
20030023	12/12/03	Apr. 2003 - Mar. 2004	OEB Cost Assessment	$ 253,562.00	12	21,130.17	(1)
40510030	07/21/2004	Apr. 2004 - July 2004	OEB Cost Assessment	$ 160,586.00	4	40,146.50	(2)
40520130	08/15/2004	Aug. 2004 - Nov. 2004	OEB Cost Assessment	$ 160,586.00	4	40,146.50	(3)
40530130	11/15/2004	Dec. 2004 - Mar. 2005	OEB Cost Assessment	$ 160,586.00	4	40,146.50	(4)
50610029	03/21/2005	Apr. 2005 - June 2005	OEB Cost Assessment	$ 210,725.00	3	70,241.67	(5)
50620029	03/06/05	July 2005 - Sep. 2005	OEB Cost Assessment	$ 210,725.00	3	70,241.67	(6)
50630029	01/09/05	Oct 2005 - Dec 2005	OEB Cost Assessment	$ 145,970.00	3	48,656.67	(7)
50640029	01/12/05	Jan 2006 - Mar 2006	OEB Cost Assessment	$ 145,970.00	3	48,656.67	(8)
60710030	03/03/06	Apr 2006 - Jun 2006	OEB Cost Assessment	$ 204,447.00	3	68,149.00	(9)
			Total	**$ 1,653,157.00**			

Enersource Hydro Mississauga Monthly Deferral based on OEB Invoices (see above analysis)

2004	**OEB Assessed Costs**	**Ref (see above)**	**2006 EDR Decision Award (Started May 1, 2006)**	**2004 Balance Oustanding Requested in 2008 Rate Application**	
January	$ 21,130.17	(1)			
February	$ 21,130.17	(1)			
March	$ 21,130.17	(1)			
April	$ 40,146.50	(2)			
May	$ 40,146.50	(2)			
June	$ 40,146.50	(2)			
July	$ 40,146.50	(2)			
August	$ 40,146.50	(3)			
September	$ 40,146.50	(3)			
October	$ 40,146.50	(3)			
November	$ 40,146.50	(3)			
December	$ 40,146.50	(4)			
	$ 424,709.00		**$ 384,000.00**	**$ 40,709.00**	
2005	**Invoices**			**2005 Balance Requested in 2008 Rate Application**	
January	$ 40,146.50	(4)			
February	$ 40,146.50	(4)			
March	$ 40,146.50	(4)			
April	$ 70,241.67	(5)			
May	$ 70,241.67	(5)			
June	$ 70,241.67	(5)			
July	$ 70,241.67	(6)			
August	$ 70,241.67	(6)			
September	$ 70,241.67	(6)			
October	$ 48,656.67	(7)			
November	$ 48,656.67	(7)			
December	$ 48,656.67	(7)			
	$ 687,859.50			**$ 687,859.50**	
2006	**Invoices**			**2006 Balance Requested in 2008 Rate Application**	
January	$ 48,656.67	(8)			
February	$ 48,656.67	(8)			
March	$ 48,656.67	(8)			
April	$ 68,149.00	(9)			
	$ 214,119.00			**$ 214,119.00**	
Total (a)	**$ 1,326,687.50**	**(b)**	**384,000.00**		
			Balance to be Recovered (c)	**$ 942,687.50**	-
			Forecasted Interest	**$ 179,009.00**	
				$ 1,121,696.50	

Note - Balance to be recovered **(c)** is Total of 2004 - 2006 OEB Assessed Costs **(a)** less 2006 OEB EDR Decision Award **(b)**

Board Staff Technical Conference Question # 30

Reference: Board Staff Interrogatory No. 44

a. Does Run 1 or Run 2 of the Informational Filing (EB-2006-0247) more closely represent the customer classification in the Application? Please file it as an official part of the record of this Application.

b. Enersource did not provide a reconciliation between the continuity schedule and the December 31, 2006 RRR submission as asked in the interrogatory.

c. Enersource did not provide a reconciliation between the continuity schedule and the amounts claimed (did not map which accounts went with each claim in ExG/Sc2/Tab3/pg1) as asked in the interrogatory.

d. There are no corresponding offsets to entries into account 1590 for 2005 or 2006 in the continuity schedule when regulatory asset accounts were cleared as part of a rates proceeding.

e. Balance in account 1518 as of December 31, 2006 does not match one provided in Question #44 either in December 31, 2006 ending balance, or "Total Claim" balance.

f. Did not show transaction history for account 1555, 1556, 1565, and 1566 in continuity schedule.

g. No balance or transactions in 1550 in continuity schedule despite 2006 EDR decision providing LV charges.

h. Please complete the table with accounts 1555, 1556, 1565, and 1566.

i. Did not show closing of 1570 and 1571 in the spreadsheet – should have balances Jan 1 2005 and subsequent closure due to rate case.

j. Why is Enersource forecasting carrying charges only on account 1508, 1525, and 1590? Please state the balances for all regulatory deferral and variance accounts if carrying charges were forecasted to April 30th, 2008 on December 31, 2006 balances.

Response 30. a)

Please see Question #27. f) response.

Response: 30. b-j)

b) **Please find attached a reconciliation between the continuity schedule and the December 31, 2006 RRR Filing.**

c) **Please find attached a reconciliation between the continuity schedule and the amounts claimed in ExG/Sc2/Tab3/pg1.**

d) **Enersource has revised the Continuity Schedule to include the balances and offsets to entries in account 1590 relating to the Phase 2 Decision for 2005, as instructed by the Board staff. For 2006, the offsets for regulatory balances returned to customers as part of the Boards Decision on Motion (EB-2006-0109) on October 3, 2006 were reflected in Board IR#44. In the attached revised continuity schedule the interest portion offset was re-classed to accurately reflect interest under transfer of Board approved amounts to 1590.**

e) **The total claim balance was different by $102 which is related to a standard charge revenue adjustment made after the December 31, 2006 RRR Filing. The balance in Account 1518 as of December 31, 2006 in Board IR#44 agrees to the December 31, 2006 balance as per RRR filing. Please see reconciliation in spreadsheet #30(b).**

f) **Enersource has updated the continuity schedule to reflect transaction history for account 1555, 1556, 1565 and 1566. Please see revised continuity schedule in response to question #30 (d).**

g) **Enersource is an embedded distributor of Hydro One's low voltage system and seeks to claim an estimated recovery of $252,886 in low voltage charges for the 2008 rate year as reported in G/2/3. The estimated amount for recovery is based on The OEB Decision and Order issued to Enersource Hydro Mississauga on April 12, 2006 to be effective on May 1, 2006. The LV Charge balance reported in the Board Staff Interrogatory #44 of ($221,698) was the balance as at December 31, 2006.**

h) **Enersource has completed the table for accounts 1555, 1556, 1565 and 1566. Please see response to #30 (f) and revised continuity schedule in #30 (d).**

i) **Enersource has revised continuity schedule #30 (d) to reflect opening balances and subsequent closure of accounts 1570 and 1571.**

j) **Enersource forecasted the carrying charges to April 30, 2008 for accounts 1508, 1525, 1590 and 1592 as these are the accounts for which Enersource proposes to clear the entire balance. The balances for all regulatory deferral and variance accounts for which carrying charges were forecasted to April 30, 2008 on December 31, 2006 balances is shown in the attached spreadsheet #30 (j).**

Board #44

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga	**LICENCE NUMBER**	ED-2003-0017
NAME OF CONTACT	Jeff Keizer	**DOCID NUMBER**	EB-2007-0706
E-mail Address	jkeizer@enersource.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	908-283-4105
Date	22-Nov-07	**(extension)**	
Question	**TCQ #30 (d)**		

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge	1580	$ 11,410,334	$ 5,760,980		$ (11,851,318)		$ 5,319,996	$ (23,595)	$ 106,957	$ 83,363
RSVA - One-time Wholesale Market Service	1582	$ 1,859,798	$ 459,133		$ (1,420,608)		$ 898,322	$ 21,275	$ 43,345	$ 64,620
RSVA - Retail Transmission Network Charge	1584	$ (4,455,794)	$ 1,721,603		$ 2,786,325		$ 52,134	$ (57,140)	$ 35,084	$ (22,056)
RSVA - Retail Transmission Connection Charge	1586	$ (6,860,683)	$ (629,732)		$ 4,410,032		$ (3,080,384)	$ (89,386)	$ (129,494)	$ (218,880)
Sub-Totals		$ 1,953,654	$ 7,311,984		$ (6,075,569)	$ -	$ 3,190,069	$ (148,845)	$ 55,892	$ (92,953)

Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga	**LICENCE NUMBER**	ED-2003-0017
NAME OF CONTACT	Jeff Keizer	**DOCID NUMBER**	EB-2007-0706
E-mail Address	jkeizer@enersource.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	908-283-4105
Date	22-Nov-07	**(extension)**	
Question	**TCQ #30 (d)**		

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05 [1]**	**Transactions (additions) during 2005, excluding interest and adjustments [6]**	**Transactions (reductions) during 2005, excluding interest and adjustments [6]**	**Adjustments during 2005 - instructed by Board [2]**	**Adjustments during 2005 - other [3]**	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 424,709	$ 687,860				$ 1,112,568	$ 10,223	$ 41,998	$ 52,221
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 874,227	$ 1,041,002				$ 1,915,229	$ -	$ 48,948	$ 48,948
Other Regulatory Assets - Sub-Account - Other[7]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other[7]	1508						$ -			$ -
Other Regulatory Assets - Sub-Account - Other[7]	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 8,224	$ 65,403				$ 73,627	$ 262	$ 2,260	$ 2,521
Retail Cost Variance Account - STR	1548	$ 51,395	$ 87,436				$ 138,831	$ 1,005	$ 6,390	$ 7,396
Misc. Deferred Debits	1525	$ 237,391	$ 3,831		$ (241,221)		$ (0)	$ -	$ -	$ -
LV Variance Account (Note 10)	1550	$ -	$ -				$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555						$ -			$ -
Smart Meter OM&A Variance	1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565		$ 1,906,802		$ (6,885,830)		$ (4,979,028)	$ -	$ -	$ -
CDM Contra	1566		$ (1,906,802)		$ 6,885,830		$ 4,979,028			$ -
Qualifying Transition Costs[5]	1570	$ 11,358,406	$ 164,765	n/a	$ (11,523,171)		$ 0			$ -
Pre-Market Opening Energy Variances Total[5]	1571	$ 11,054,131	$ 156,369	n/a	$ (11,210,500)		$ (0)			$ -
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 24,008,483	$ 2,206,666	$ -	$ (22,974,893)	$ -	$ 3,240,256	$ 11,489	$ 99,597	$ 111,086

Board #44

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga	**LICENCE NUMBER**	ED-2003-0017
NAME OF CONTACT	Jeff Keizer	**DOCID NUMBER**	EB-2007-0706
E-mail Address	jkeizer@enersource.com		
VERSION NUMBER	v3.0	**PHONE NUMBER**	908-283-4105
Date	22-Nov-07	**(extension)**	
Question	**TCQ #30 (d)**		

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
Deferred Payments in Lieu of Taxes	1562				**see PILs reconciliation requested**					
2006 PILs & Taxes Variance	1592				**see PILs reconciliation requested**					
Sub-Totals					**see PILs reconciliation requested**					
Total		$ 25,962,137	$ 9,518,650	$ -	$ (29,050,462)	$ -	$ 6,430,325	$ (137,355)	$ 155,489	$ 18,134
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account[8]	1563				**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)	1588	$ (3,114,029)	$ (8,329,810)		$ 254,369		$ (11,189,470)	$ (115,492)	$ (593,445)	$ (708,937)
RSVA - Power - Sub-Account - Global Adjustment[9]	1588	$ -	$ (6,402,236)				$ (6,402,236)	$ -	$ (334,123)	$ (334,123)
Recovery of Regulatory Asset Balances	1590	$ (5,254,873)	$ 1,049,724	$ (7,705,630)	$ 28,796,093		$ 16,885,313	$ (115,426)	$ 892,285	$ 776,859

Y:\All Attachments\[Board TCQ #30 (d).xls]Cont.Schedule- TCQ #30

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
- Per the OEB's December 9, 2004 Decision with Reasons - Phase 2 of the Regulatory Assets Review
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
- Account 1590 Transactions - Per the OEB's December 9, 2004 Decision with Reasons - Phase 2 of the Regulatory Assets Review
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2006 closing principal balance.

Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	44

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06
RSVA - Wholesale Market Service Charge	1580	$ 5,319,996	$ (10,216,327)		$ -	$ -	$ 267,757	$ (4,628,574)	$ 83,363	$ 76,724
RSVA - One-time Wholesale Market Service	1582	$ 898,322	$ -		$ -	$ -	$ (460,984)	$ 437,338	$ 64,620	$ 45,636
RSVA - Retail Transmission Network Charge	1584	$ 52,134	$ 1,358,422		$ -	$ -	$ -	$ 1,410,556	$ (22,056)	$ (6,962)
RSVA - Retail Transmission Connection Charge	1586	$ (3,080,384)	$ 676,484				$ -	$ (2,403,900)	$ (218,880)	$ (179,336)
Sub-Totals		$ 3,190,069	$ (8,181,421)		$ -	$ -	$ (193,227)	$ (5,184,580)	$ (92,953)	$ (63,938)

Board #44

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	44

Account Description	**Account Number**	**2006** Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,112,568	$ 214,120	$ (127,231)				$ 1,199,458	$ 52,221	$ 60,594
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 1,915,229	$ 330,735	$ (289,734)				$ 1,956,230	$ 48,948	$ 89,100
Other Regulatory Assets - Sub-Account - Other[7]	1508	$ -						$ -	$ -	
Other Regulatory Assets - Sub-Account - Other[7]	1508	$ -						$ -	$ -	
Other Regulatory Assets - Sub-Account - Other[7]	1508	$ -						$ -	$ -	
Retail Cost Variance Account - Retail	1518	$ 73,627	$ 41,202				$ (8,224)	$ 106,605	$ 2,521	$ 5,134
Retail Cost Variance Account - STR	1548	$ 138,831	$ 85,572				$ (51,395)	$ 173,008	$ 7,396	$ 9,320
Misc. Deferred Debits	1525	$ (0)	$ 21,095					$ 21,095	$ -	
LV Variance Account (Note 10)	1550	$ -	$ (218,851)					$ (218,851)	$ -	$ (2,847)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ 191,831					$ 191,831	$ -	$ 725
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ (453,280)					$ (453,280)	$ -	$ (6,069)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -	$ -					$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ 190,385					$ 190,385	$ -	$ 198
Conservation and Demand Management Expenditures and Recoveries	1565	$ (4,979,028)	$ 3,349,437	$ (1,377,166)				$ (3,006,757)	$ -	$ -
CDM Contra	1566	$ 4,979,028	$ (3,349,437)	$ 1,377,166				$ 3,006,757	$ -	
Qualifying Transition Costs[5]	1570	$ 0	n/a	n/a				$ 0	$ -	
Pre-Market Opening Energy Variances Total[5]	1571	$ (0)	n/a	n/a				$ (0)	$ -	
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -	
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -	
Other Deferred Credits	2425	$ -						$ -	$ -	
Sub-Totals		$ 3,240,256	$ 402,809	$ (416,965)	$ -	$ -	$ (59,619)	$ 3,166,480	$ 111,086	$ 156,154

Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	44

Account Description	**Account Number**	**2006** Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06
Deferred Payments in Lieu of Taxes	1562						**see PILs reconciliation requested**			
2006 PILs & Taxes Variance	1592						**see PILs reconciliation requested**			
Sub-Totals							**see PILs reconciliation requested**			
Total		$ 6,430,325	$ (7,778,613)	$ (416,965)	$ -	$ -	$ (252,846)	$ (2,018,099)	$ 18,134	$ 92,217
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [5]	1563						**see PILs reconciliation requested**			
RSVA - Power (including Global Adjustment)	1588	$ (11,189,470)	$ 9,470,217				$ 2,850,219	$ 1,130,966	$ (708,937)	$ (259,792)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ (6,402,236)	$ 13,115,415					$ 6,713,179	$ (334,123)	$ 148,350
Recovery of Regulatory Asset Balances	1590	$ 16,885,313	$ 388,262	$ (7,372,745)			$ (2,597,373)	$ 7,303,458	$ 776,859	$ 680,746

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Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	44

Account Description		**Account Number**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec 31-06**	**Closing Balance December 31, 2006 and 2.1.1 RRR Balances**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [9]**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [9]**
RSVA - Wholesale Market Service Charge		1580	$ 23,595	$ 183,682	$ (4,444,892)		
RSVA - One-time Wholesale Market Service		1582	$ (21,275)	$ 88,982	$ 526,320		
RSVA - Retail Transmission Network Charge		1584	$ -	$ (29,018)	$ 1,381,538		
RSVA - Retail Transmission Connection Charge		1586	$ -	$ (398,216)	$ (2,802,116)		
					$ -		
	Sub-Totals		$ 2,320	$ (154,570)	$ (5,339,150)	$ -	$ -

Board #44

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	44

Account Description	**Account Number**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec 31-06**	**Closing Balance December 31, 2006 and 2.1.1 RRR Balances**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [9]**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [9]**
				$ -		
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508		$ 112,815	$ 1,312,273	$ 55,055	$ 18,352
Other Regulatory Assets - Sub-Account - Pension Contributions	1508		$ 138,048	$ 2,094,278	$ 89,791	$ 29,930
Other Regulatory Assets - Sub-Account - Other′	1508		$ -	$ -		
Other Regulatory Assets - Sub-Account - Other′	1508		$ -	$ -		
Other Regulatory Assets - Sub-Account - Other′	1508		$ -	$ -		
Retail Cost Variance Account - Retail	1518	$ (261)	$ 7,394	$ 113,999		
Retail Cost Variance Account - STR	1548	$ (1,005)	$ 15,710	$ 188,718		
Misc. Deferred Debits	1525		$ -	$ 21,095	$ 1,730	$ 322
LV Variance Account (Note 10)	1550		$ (2,847)	$ (221,698)		$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555		$ 725	$ 192,556		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555		$ (6,069)	$ (459,349)		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555		$ -	$ -		
Smart Meter OM&A Variance	1556		$ 198	$ 190,583		
Conservation and Demand Management Expenditures and Recoveries	1565	$ -	$ -	$ (3,006,757)		
CDM Contra	1566		$ -	$ 3,006,757		
Qualifying Transition Costs[5]	1570		$ -	$ 0		
Pre-Market Opening Energy Variances Total[5]	1571		$ -	$ (0)		
Extra-Ordinary Event Costs	1572		$ -	$ -		
Deferred Rate Impact Amounts	1574		$ -	$ -		
Other Deferred Credits	2425		$ -	$ -		
				$ -		
Sub-Totals		$ (1,266)	$ 265,974	$ 3,432,455	$ 146,576	$ 48,604

Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	44

Account Description		**Account Number**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec 31-06**	**Closing Balance December 31, 2006 and 2.1.1 RRR Balances**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [9]**	**Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [9]**
					$ -		
Deferred Payments in Lieu of Taxes		1562			$ (2,115,347)		
2006 PILs & Taxes Variance		1592			$ 71,909	3,142	1,048
					$ -		
	Sub-Totals				$ -		
					$ -		
	Total		$ 1,054	$ 111,404	$ (1,906,695)	$ 146,576	$ 48,604
					$ -		
The following is not included in the total claim but is included on a memo basis:					$ -		
Deferred PILs Contra Account[8]		1563			$ 2,115,347		
RSVA - Power (including Global Adjustment)		1588	$ 115,492	$ (853,238)	$ 277,728		
RSVA - Power - Sub-Account - Global Adjustment[4]		1588		$ (185,773)	$ 6,527,406		
Recovery of Regulatory Asset Balances		1590	$ (116,544)	$ 1,341,061	$ 8,644,519	$ 302,515	$ 100,838

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Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	

Account Description	**Account Number**	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008**	**Projected Interest from Jan 1, 2007 to April 30, 2007 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007**	**Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008**	**Total Claim**
RSVA - Wholesale Market Service Charge	1580	$ (4,444,892)					$ (4,444,892)
RSVA - One-time Wholesale Market Service	1582	$ 526,320					$ 526,320
RSVA - Retail Transmission Network Charge	1584	$ 1,381,538					$ 1,381,538
RSVA - Retail Transmission Connection Charge	1586	$ (2,802,116)					$ (2,802,116)
Sub-Totals		$ (5,339,150)	$ -	$ -	$ -	$ -	$ (5,339,150)

Board #44
SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	

Account Description	**Account Number**	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008**	**Projected Interest from Jan 1, 2007 to April 30, 2007 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007**	**Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008**	**Total Claim**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,385,679	$ (187,872)	$ (68,897)	$ (3,965)	$ (3,248)	$ 1,121,697
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 2,214,000	$ (431,708)	$ (152,660)	$ (9,086)	$ (7,456)	$ 1,613,090
Other Regulatory Assets - Sub-Account - Other[4]	1508	$ -					$ -
Other Regulatory Assets - Sub-Account - Other[4]	1508	$ -					$ -
Other Regulatory Assets - Sub-Account - Other[4]	1508	$ -					$ -
Retail Cost Variance Account - Retail	1518	$ 113,999					$ 113,999
Retail Cost Variance Account - STR	1548	$ 188,718					$ 188,718
Misc. Deferred Debits	1525	$ 23,147	$ -	$ -	$ -	$ -	$ 23,147
LV Variance Account (Note 10)	1550	$ (221,698)					$ (221,698)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 192,556					$ 192,556
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (459,349)					$ (459,349)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -					$ -
Smart Meter OM&A Variance	1556	$ 190,583					$ 190,583
Conservation and Demand Management Expenditures and Recoveries	1565	$ (3,006,757)					$ (3,006,757)
CDM Contra	1566	$ 3,006,757					$ 3,006,757
Qualifying Transition Costs[5]	1570	$ 0					$ 0
Pre-Market Opening Energy Variances Total[6]	1571	$ (0)					$ (0)
Extra-Ordinary Event Costs	1572	$ -					$ -
Deferred Rate Impact Amounts	1574	$ -					$ -
Other Deferred Credits	2425	$ -					$ -
Sub-Totals		$ 3,627,635	$ (619,580)	$ (221,557)	$ (13,051)	$ (10,704)	$ 2,762,743

Board #44

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Enersource Hydro Mississauga
NAME OF CONTACT	Jeff Keizer
E-mail Address	jkeizer@enersource.com
VERSION NUMBER	v3.0
Date	22-Nov-07
Question	

Account Description		**Account Number**	**Claim before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008**	**Projected Interest from Jan 1, 2007 to April 30, 2007 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007**	**Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008**	**Total Claim**
Deferred Payments in Lieu of Taxes		1562	$ (2,115,347)					$ (2,115,347)
2006 PILs & Taxes Variance		1592	$ 76,099	(101,343)	$ -	(3,682)	(1,551)	$ (30,477)
	Sub-Totals		$ (2,039,248)					$ (2,145,824)
	Total		$ (3,750,763)	$ (619,580)	$ (221,557)	$ (13,051)	$ (10,704)	$ (4,722,231)
The following is not included in the total claim but is included on a memo basis:								
Deferred PILs Contra Account°		1563	$ 2,115,347					$ 2,115,347
RSVA - Power (including Global Adjustment)		1588	$ 277,728					$ 277,728
RSVA - Power - Sub-Account - Global Adjustment[4]		1588	$ 6,527,406					$ 6,527,406
Recovery of Regulatory Asset Balances		1590	$ 9,047,872	$ (5,392,170)	$ (1,927,904)	$ (102,570)	$ (87,807)	$ 1,537,421

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This Spreadsheet is related to Board TCQ 30 (c) - Part 2

DERIVATION OF PROPOSED RATE RIDERS FOR 2008 TEST YEAR (000's)

	Allocation to Customer Classes %	Allocation to Customer Classes % for LRAM	Allocation to Customer Classes % for SSM	Account 1525 Ontario Price Credit Admin Costs	Account 1592 Large Corporation Tax Over Recovery	Account 1508 Deferred OEB Costs (Jan. 1, 2005 to Apr. 30, 2006)	Account 1508 OMERS Pension Deferral (Jan. 1, 2005 to Apr. 30, 2006)	Account 1590 Interest on Regulatory Assets	Various (see below) RSVA Balances returned to customers (as at Dec.31, 2006)	Sub-Total before Low Voltage	Account 1550 LV Charges for 2008 Test Year	Sub-Total Including Low Voltage	LRAM to April 30, 2007	SSM to April 30, 2007	Total to be recovered over 1 year	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders
	Total for customer class as % of Total for all classes	**Total kWh savings per class / Total kWh savings**	**Total kWh savings per class / Total kWh savings**	**$ 23.1**	**$ (30.5)**	**$ 1,121.7**	**$ 1,613.1**	**$ 1,537.4**	**$ (11,286.0)**	**$ (7,021.1)**	**$ 252.9**	**$ (6,768.2)**	**$ 370.2**	**$ 1,279.7**	**$ (5,118.3)**			
RESIDENTIAL	35.82%	97.96%	56.67%	$ 8.3	$ (10.9)	$ 401.8	$ 577.8	$ 550.7	$ (4,042.6)	$ (2,515.0)	$ 56.4	$ (2,458.5)	$ 362.7	$ 725.2	$ (1,370.6)	1,547,398,184		$ (0.0009)
General Service < 50 kW	13.82%	1.76%	0.12%	$ 3.2	$ (4.2)	$ 155.1	$ 223.0	$ 212.5	$ (1,560.1)	$ (970.5)	$ 21.3	$ (949.2)	$ 6.5	$ 1.5	$ (941.2)	646,726,132		$ (0.0015)
Small Commercial	0.78%	0.00%	0.00%	$ 0.2	$ (0.2)	$ 8.8	$ 12.6	$ 12.1	$ (88.5)	$ (55.0)	$ 0.4	$ (54.6)	$ -	$ -	$ (54.6)	11,905,587		$ (0.0046)
General Service 50 kW - 499 kW	28.85%	0.19%	1.87%	$ 6.7	$ (8.8)	$ 323.7	$ 465.4	$ 443.6	$ (3,256.4)	$ (2,025.9)	$ 83.1	$ (1,942.8)	$ 0.7	$ 24.0	$ (1,918.1)		6,415,732	$ (0.2990)
General Service 500 kW - 4999 k\	14.55%	0.09%	26.75%	$ 3.4	$ (4.4)	$ 163.3	$ 234.8	$ 223.8	$ (1,642.7)	$ (1,021.9)	$ 67.3	$ (954.6)	$ 0.3	$ 342.3	$ (612.0)		5,310,121	$ (0.1152)
Large Use (> 5000 kW)	5.69%	0.00%	14.59%	$ 1.3	$ (1.7)	$ 63.8	$ 91.7	$ 87.4	$ (641.8)	$ (399.2)	$ 23.3	$ (376.0)	$ -	$ 186.7	$ (189.3)		1,720,956	$ (0.1100)
Street Lighting	0.48%	0.00%	0.00%	$ 0.1	$ (0.1)	$ 5.4	$ 7.7	$ 7.4	$ (54.0)	$ (33.6)	$ 1.1	$ (32.5)	$ -	$ -	$ (32.5)		115,190	$ (0.2822)
TOTALS	**100.00%**	**100.00%**	**100.00%**	**$ 23.1**	**$ (30.5)**	**$ 1,121.7**	**$ 1,613.1**	**$ 1,537.4**	**$ (11,286.0)**	**$ (7,021.1)**	**$ 252.9**	**$ (6,768.2)**	**$ 370.2**	**$ 1,279.7**	**$ (5,118.3)**			

RSVAs - Various (Break Out)

	Allocation to Customer Classes %	Account 1518	Account 1548	Account 1580	Account 1582	Account 1584	Account 1586	Account 1588	Total RSVAs
	Total for customer class as % of Total for all classes	**114.1**	**188.7**	**(4,444.9)**	**526.3**	**1,381.5**	**(2,802.1)**	**(6,249.7)**	(11,286.0)
RESIDENTIAL	35.82%	40.9	67.6	(1,592.1)	188.5	494.9	(1,003.7)	(2,238.6)	(4,042.6)
General Service < 50 kW	13.82%	15.8	26.1	(614.4)	72.8	191.0	(387.3)	(863.9)	(1,560.1)
Small Commercial	0.78%	0.9	1.5	(34.8)	4.1	10.8	(22.0)	(49.0)	(88.5)
General Service 50 kW - 499 kW	28.85%	32.9	54.5	(1,282.5)	151.9	398.6	(808.5)	(1,803.3)	(3,256.4)
General Service 500 kW - 4999 k\	14.55%	16.6	27.5	(647.0)	76.6	201.1	(407.8)	(909.6)	(1,642.7)
Large Use (> 5000 kW)	5.69%	6.5	10.7	(252.8)	29.9	78.6	(159.3)	(355.4)	(641.8)
Street Lighting	0.48%	0.5	0.9	(21.3)	2.5	6.6	(13.4)	(29.9)	(54.0)
TOTALS	**100.00%**	**114.1**	**188.7**	**(4,444.9)**	**526.3**	**1,381.5**	**(2,802.1)**	**(6,249.7)**	**(11,286.0)**

Enersource Hydro Mississauga
Reconciliation of Board Staff IR Continuity Schedule to December 31, 2006 2.1.1 RRR Filing and to Total Claim
Board TCQ # 30 © - part 1 page 1

		December 31, 2006			December 31, 2006		
		Revised IR # 44 - Continuity Schedule			2.1.1 RRR		
Account Description	**Account Number**	**Principal**	**Interest**	**Balance**	**Principal**	**Interest**	**Balance**
RSVA - Wholesale Market Service Charge	1580	$ (4,628,574)	$ 183,682	$ (4,444,892)	$ (4,628,574)	$ 183,682	$ (4,444,892)
RSVA - One-time Wholesale Market Service	1582	$ 437,338	$ 88,982	$ 526,320	$ 437,338	$ 88,982	$ 526,320
RSVA - Retail Transmission Network Charge	1584	$ 1,410,556	$ (29,018)	$ 1,381,538	$ 1,410,556	$ (29,018)	$ 1,381,538
RSVA - Retail Transmission Connection Charge	1586	$ (2,403,900)	$ (398,216)	$ (2,802,116)	$ (2,403,900)	$ (398,216)	$ (2,802,116)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments **(1)**	1508	$ 1,199,458	$ 112,815	$ 1,312,273	$ 1,199,458	$ 112,815	$ 1,312,273
Other Regulatory Assets - Sub-Account - Pension Contributions **(1)**	1508	$ 1,956,230	$ 138,048	$ 2,094,278	$ 1,956,230	$ 138,048	$ 2,094,278
Retail Cost Variance Account - Retail	1518	$ 106,605	$ 7,394	$ 113,999	$ 106,605	$ 7,394	$ 113,999
Retail Cost Variance Account - STR	1548	$ 173,008	$ 15,710	$ 188,718	$ 173,008	$ 15,710	$ 188,718
Misc. Deferred Debits **(2)**	1525	$ 21,095	$ -	$ 21,095	$ 21,095	$ -	$ 21,095
LV Variance Account **(3)**	1550	$ (218,851)	$ (2,847)	$ (221,698)	$ (218,851)	$ (2,847)	$ (221,698)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital **(4)**	1555	$ 191,831	$ 725	$ 192,556	$ 191,831	$ 725	$ 192,556
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries **(4)**	1555	$ (453,280)	$ (6,069)	$ (459,349)	$ (453,280)	$ (6,069)	$ (459,349)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs **(4)**	1555	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ 190,385	$ 198	$ 190,583	$ 190,385	$ 198	$ 190,583
Conservation and Demand Management Expenditures and Recoveries	1565	$ (3,006,757)	$ -	$ (3,006,757)	$ (3,006,757)	$ -	$ (3,006,757)
CDM Contra	1566	$ 3,006,757	$ -	$ 3,006,757	$ 3,006,757	$ -	$ 3,006,757
Qualifying Transition Costs	1570			$ -			$ -
Pre-Market Opening Energy Variances Total	1571			$ -			$ -
Extra-Ordinary Event Costs	1572			$ -			$ -
Deferred Rate Impact Amounts	1574			$ -			$ -
Other Deferred Credits	2425			$ -			$ -
Deferred Payments in Lieu of Taxes	1562			$ (2,115,347)	$ -	$ -	$ (2,115,347)
2006 PILs & Taxes Variance	1592			$ 71,909	$ -	$ -	$ 71,909
The following is not included in the total claim but is included on a memo basis:							
Deferred PILs Contra Account	1563			$ 2,115,347	$ -	$ -	$ 2,115,347
RSVA - Power (including Global Adjustment) **(5)**	1588	$ 1,130,966	$ (853,238)	$ 277,728	$ 1,130,966	$ (853,238)	$ 277,728
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 6,713,179	$ (185,773)	$ 6,527,406	$ 6,713,179	$ (185,773)	$ 6,527,406
Recovery of Regulatory Asset Balances **(6)**	1590	$ 7,303,458	$ 1,341,061	$ 8,644,519	$ 7,186,913	$ 1,457,606	$ 8,644,519
LRAM							
SSM							

Notes:

(1) - Grouped in 2.1.1 RRR Filing (December 31, 2006)

	Principal	Interest	Balance
Other Regulatory Assets (2.1.1 RRR)	$ 3,155,688	$ 250,863	$ 3,406,551

(2) Includes $762 in interest booked in 2007 that was related to December 31, 2006 balance

(3) EHM is requesting to recover $252,886 in forecasted Low voltage charges for the 2008 rate year through a rate rider.
This estimate is based on previous OEB Board approved LV recoveries.

	Principal	Interest	Balance
(4) Smart Meter Captal and recovery Offset Variance (2.1.1 RRR	$ (261,449)	$ (5,344)	$ (266,793)

(5) - Grouped in 2.1.1 RRR Filing (December 31, 2006 - (Ref: Account 1588 Refiling of September 20, 2007))

	Principal	Interest	Balance
RSVA Power	$ (5,582,213)	$ (667,465)	$ (6,249,678)
RSVA Power-Sub Account Global Adjustment	$ 6,713,179	$ (185,773)	$ 6,527,406
	$ 1,130,966	$ (853,238)	$ 277,728

(6) Interest Reclassed. As at December 31, 2006, the amount refunded of ($2,713,917) includes interest which was reclassified subsequent to 2.1.1 Filing at end of December 31, 2006.

(7) Adjustment

a) RCVA 1518 - The total claim balance was different by $102 which is related to a standard charge revenue adjustment made after the December 31, 2006 RRR Filing
b) Enersource requested RSVA Power excluding Global Adjustment. The balance included Global Adjustment as presented in IR#44.

Enersource Hydro Mississauga

Reconciliation of Board Staff IR Continuity Schedule to December 31, 2006 2.1.1 RRR Filing and to Total Claim

Board TCQ # 30 © - part 1 page 1

Board TCQ # 30 © Part 1 page 2

Account Description	Balance 31-Dec-06	Transactions 2007	Interest 2007	Transactions 2008	Interest 2008	Adjustment	Accounts That Makes up Total Claim Balance	Period upon which Claim is Based
	Accounts That Makes up Total Claim Balance	Forecasted Transactions & Interest						
RSVA - Wholesale Market Service Charge	$ (4,444,892)	-	-	-	-	-	$ (4,444,892)	December 31, 2006
RSVA - One-time Wholesale Market Service	$ 526,320	-	-	-	-	-	$ 526,320	December 31, 2006
RSVA - Retail Transmission Network Charge	$ 1,381,538	-	-	-	-	-	$ 1,381,538	December 31, 2006
RSVA - Retail Transmission Connection Charge	$ (2,802,116)	-	-	-	-	-	$ (2,802,116)	December 31, 2006
Other Regulatory Assets - Sub-Account - OEB Cost Assessments **(1)**	$ 1,312,273	(187,872)	51,090	(68,897)	15,104		$ 1,121,697	Forecasted to April 30, 2008
Other Regulatory Assets - Sub-Account - Pension Contributions **(1)**	$ 2,094,278	(431,708)	80,706	(152,660)	22,474		$ 1,613,090	Forecasted to April 30, 2008
Retail Cost Variance Account - Retail	$ 113,999	-	-	-	-	102	$ 114,101	December 31, 2006
Retail Cost Variance Account - STR	$ 188,718	-	-	-	-	-	$ 188,718	December 31, 2006
Misc. Deferred Debits **(2)**	$ 21,095	-	1,730	-	322	-	$ 23,147	Forecasted to April 30, 2008
LV Variance Account **(3)**	$ (221,698)						$ 252,886	2008 Test Year Charges
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital **(4)**							$ -	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries **(4)**							$ -	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs **(4)**							$ -	
Smart Meter OM&A Variance							$ -	
Conservation and Demand Management Expenditures and Recoveries							$ -	
CDM Contra							$ -	
Qualifying Transition Costs							$ -	
Pre-Market Opening Energy Variances Total							$ -	
Extra-Ordinary Event Costs							$ -	
Deferred Rate Impact Amounts							$ -	
Other Deferred Credits							$ -	
Deferred Payments in Lieu of Taxes							$ -	
2006 PILs & Taxes Variance	$ 71,909	$ (101,343)	$ (540)		$ (503)		$ (30,477)	Forecasted to April 30, 2008
The following is not included in the total claim but is included on a memo basis:							$ -	
Deferred PILs Contra Account							$ -	
RSVA - Power (including Global Adjustment) **(5)**	$ 277,728					$ (6,527,406)	$ (6,249,678)	See Note (5) - December 31, 2006
RSVA - Power - Sub-Account - Global Adjustment							$ -	
Recovery of Regulatory Asset Balances **(6)**	$ 8,644,519	$ (5,392,170)	$ 199,945	$ (1,927,904)	$ 13,031		$ 1,537,421	Forecasted to April 30, 2008
LRAM							$ 370,246	Balances to April 30, 2007
SSM							$ 1,279,685	Balances to April 30, 2007
							$ (5,118,313)	

Enersource Hydro Mississauga
Reconciliation of Board Staff IR Continuity Schedule to December 31, 2006 2.1.1 RRR Filing and to Total Claim
Board TCQ # 30 (b)

		Revised IR # 44 - Continuity Schedule			2.1.1 RRR			Variance		
		December 31, 2006			December 31, 2006					
Account Description	**Account Number**	**Principal**	**Interest**	**Balance**	**Principal**	**Interest**	**Balance**	**Principal**	**Interest**	**Balance**
RSVA - Wholesale Market Service Charge	1580	$ (4,628,574)	$ 183,682	$ (4,444,892)	$ (4,628,574)	$ 183,682	$ (4,444,892)	-	-	-
RSVA - One-time Wholesale Market Service	1582	$ 437,338	$ 88,982	$ 526,320	$ 437,338	$ 88,982	$ 526,320	-	-	-
RSVA - Retail Transmission Network Charge	1584	$ 1,410,556	$ (29,018)	$ 1,381,538	$ 1,410,556	$ (29,018)	$ 1,381,538	-	-	-
RSVA - Retail Transmission Connection Charge	1586	$ (2,403,900)	$ (398,216)	$ (2,802,116)	$ (2,403,900)	$ (398,216)	$ (2,802,116)	-	-	-
Other Regulatory Assets - Sub-Account - OEB Cost Assessments **(1)**	1508	$ 1,199,458	$ 112,815	$ 1,312,273	$ 1,199,458	$ 112,815	$ 1,312,273	-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions **(1)**	1508	$ 1,956,230	$ 138,048	$ 2,094,278	$ 1,956,230	$ 138,048	$ 2,094,278	-	-	-
Retail Cost Variance Account - Retail	1518	$ 106,605	$ 7,394	$ 113,999	$ 106,605	$ 7,394	$ 113,999	-	-	-
Retail Cost Variance Account - STR	1548	$ 173,008	$ 15,710	$ 188,718	$ 173,008	$ 15,710	$ 188,718	-	-	-
Misc. Deferred Debits	1525	$ 21,095	$ -	$ 21,095	$ 21,095	$ -	$ 21,095	-	-	-
LV Variance Account	1550	$ (218,851)	$ (2,847)	$ (221,698)	$ (218,851)	$ (2,847)	$ (221,698)	-	-	-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital **(2)**	1555	$ 191,831	$ 725	$ 192,556	$ 191,831	$ 725	$ 192,556	-	-	-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries **(2)**	1555	$ (453,280)	$ (6,069)	$ (459,349)	$ (453,280)	$ (6,069)	$ (459,349)	-	-	-
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs **(2)**	1555	$ -	$ -	$ -	$ -	$ -	$ -	-	-	-
Smart Meter OM&A Variance	1556	$ 190,385	$ 198	$ 190,583	$ 190,385	$ 198	$ 190,583	-	-	-
Conservation and Demand Management Expenditures and Recoveries	1565	$ (3,006,757)	$ -	$ (3,006,757)	$ (3,006,757)	$ -	$ (3,006,757)	-	-	-
CDM Contra	1566	$ 3,006,757	$ -	$ 3,006,757	$ 3,006,757	$ -	$ 3,006,757	-	-	-
Qualifying Transition Costs	1570			$ -			$ -	-	-	-
Pre-Market Opening Energy Variances Total	1571			$ -			$ -	-	-	-
Extra-Ordinary Event Costs	1572			$ -			$ -	-	-	-
Deferred Rate Impact Amounts	1574			$ -			$ -	-	-	-
Other Deferred Credits	2425			$ -			$ -	-	-	-
Deferred Payments in Lieu of Taxes	1562			$ (2,115,347)	$ -	$ -	$ (2,115,347)	-	-	-
2006 PILs & Taxes Variance	1592			$ 71,909	$ -	$ -	$ 71,909	-	-	-
The following is not included in the total claim but is included on a memo basis:								-	-	-
Deferred PILs Contra Account	1563			$ 2,115,347	$ -	$ -	$ 2,115,347	-	-	-
RSVA - Power (including Global Adjustment) **(3)**	1588	$ 1,130,966	$ (853,238)	$ 277,728	$ 1,130,966	$ (853,238)	$ 277,728	-	-	-
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 6,713,179	$ (185,773)	$ 6,527,406	$ 6,713,179	$ (185,773)	$ 6,527,406	-	-	-
Recovery of Regulatory Asset Balances **(4)**	1590	$ 7,303,458	$ 1,341,061	$ 8,644,519	$ 7,186,913	$ 1,457,606	$ 8,644,519	116,545	(116,545)	-

(1) Grouped in 2.1.1 RRR Filing (December 31, 2006)

	Principal	Interest	Balance
Other Regulatory Assets (2.1.1 RRR)	$ 3,155,688	$ 250,863	$ 3,406,551

(2) Smart Meter Captal and recovery Offset Variance (2.1.1 RRR

	Principal	Interest	Balance
	$ (261,449)	$ (5,344)	$ (266,793)

(3) Grouped in 2.1.1 RRR Filing (December 31, 2006 - (Ref: Account 1588 Refiling of September 20, 2007))

	Principal	Interest	Balance
RSVA Power	$ (5,582,213)	$ (667,465)	$ (6,249,678)
RSVA Power-Sub Account Global Adjustment	$ 6,713,179	$ (185,773)	$ 6,527,406
	$ 1,130,966	$ (853,238)	$ 277,728

(4) As at December 31, 2006, the amount refunded included interest which was reclassified subsequent to 2.1.1 Filing at end of December 31, 2006. This was based on the OEB Decision on Motion EB-2006-0109 on Oct 3, 2006.

Enersource Hydro Mississauga
Reconciliation of Board Staff IR Continuity Schedule to December 31, 2006 2.1.1 RRR Filing
Board TCQ #30 (j)

			December 31, 2006							Period upon which Claim is Based
Account Description	**Account Number**	**Principal**	**Interest**	**Balance**	**2007 Transactions**	**2007 Interest**	**2008 Transactions**	**2008 Interest**	**Total Claim**	
RSVA - Wholesale Market Service Charge	1580	$ (4,628,574)	$ 183,682	$ (4,444,892)					$ (4,444,892)	December 31, 2006
RSVA - One-time Wholesale Market Service	1582	$ 437,338	$ 88,982	$ 526,320					$ 526,320	December 31, 2006
RSVA - Retail Transmission Network Charge	1584	$ 1,410,556	$ (29,018)	$ 1,381,538					$ 1,381,538	December 31, 2006
RSVA - Retail Transmission Connection Charge	1586	$ (2,403,900)	$ (398,216)	$ (2,802,116)					$ (2,802,116)	December 31, 2006
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,199,458	$ 112,815	$ 1,312,273	(187,872)	51,090	(68,897)	15,103	$ 1,121,697	Forecasted to April 30, 2008
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 1,956,230	$ 138,048	$ 2,094,278	(431,708)	80,706	(152,660)	22,474	$ 1,613,090	Forecasted to April 30, 2008
Retail Cost Variance Account - Retail	1518	$ 106,707	$ 7,394	$ 114,101					$ 114,101	December 31, 2006
Retail Cost Variance Account - STR	1548	$ 173,008	$ 15,710	$ 188,718					$ 188,718	December 31, 2006
Misc. Deferred Debits	1525	$ 21,095	$ -	$ 21,095	$ -	$ 1,730	$ -	$ 322	$ 23,147	Forecasted to April 30, 2008
LV Variance Account (Note 1)	1550	$ (218,851)	$ (2,847)	$ (221,698)					$ 252,886	2008 Test Year LV Charges
2006 PILs & Taxes Variance	1592	68,445	3,464	$ 71,909	$ (101,343)	$ (540)		$ (503)	$ (30,477)	Forecasted to April 30, 2008
RSVA - Power (excluding Global Adjustment)	1588	$ (5,582,213)	$ (667,465)	$ (6,249,678)					$ (6,249,678)	See Note (2) - December 31, 2006
Recovery of Regulatory Asset Balances	1590	7,186,913	1,457,606	$ 8,644,519	$ (5,392,170)	$ 199,945	$ (1,927,904)	$ 13,031	$ 1,537,421	December 31, 2006
LRAM									$ 370,246	Balances to April 30, 2007
SSM									$ 1,279,685	Balances to April 30, 2007
Total Claim - ExG/Sc2/Tab3/pg1									$ (5,118,313)	

Note (1)
EHM is requesting to recover $252,886 in forecasted Low voltage charges for the 2008 rate year through a rate rider.
This estimate is based on previous OEB Board approved LV recoveries.

Board Staff Technical Conference Question # 31

Reference: Board Staff Interrogatory No. 45

a. Did not list in IR#45(a) all accounts and corresponding balances that are being requested to be disposed of (only showed RSVA and RCVA, and excluded 1508, 1525, 1550 and 1592) as requested in the interrogatory. Please provide the information as requested in Board Staff IR No. 45.

b. Did not provide rate rider information in 45b for 1550 – provided only for 2008 test year LV charges. Please provide the information as requested in Board Staff IR No. 45.

Response: 31. a-b)

a) **Please see the attached spreadsheet which lists all of the accounts and the composition of the balances that are being requested to be disposed of as requested in interrogatory (IR#45(a)).**

b) **Enersource is not seeking to dispose of the LV Account 1550 balance. Enersource is an embedded distributor of Hydro One's low voltage system and seeks to claim an estimated recovery of $252,886 in low voltage charges for the 2008 rate year as reported in G/2/3. The estimated amount for recovery is based on The OEB Decision and Order issued to Enersource Hydro Mississauga on April 12, 2006 to be effective on May 1, 2006. In light of the above, Enersource provided Rate Rider information for the 2008 Test Year LV Charges.**

Enersource Hydro Mississauga

Reconciliation of Board Staff IR Continuity Schedule to December 31, 2006 2.1.1 RRR Filing

Board TCQ #31 (a)

			December 31, 2006						
Account Description	**Account Number**	**Principal**	**Interest**	**Balance**	**2007 Transactions**	**2007 Interest**	**2008 Transactions**	**2008 Interest**	**Total Claim**
RSVA - Wholesale Market Service Charge	1580	$ (4,628,574)	$ 183,682	$ (4,444,892)					$ (4,444,892)
RSVA - One-time Wholesale Market Service	1582	$ 437,338	$ 88,982	$ 526,320					$ 526,320
RSVA - Retail Transmission Network Charge	1584	$ 1,410,556	$ (29,018)	$ 1,381,538					$ 1,381,538
RSVA - Retail Transmission Connection Charge	1586	$ (2,403,900)	$ (398,216)	$ (2,802,116)					$ (2,802,116)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,199,458	$ 112,815	$ 1,312,273	(187,872)	51,090	(68,897)	15,103	$ 1,121,697
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 1,956,230	$ 138,048	$ 2,094,278	(431,708)	80,706	(152,660)	22,474	$ 1,613,090
Retail Cost Variance Account - Retail	1518	$ 106,707	$ 7,394	$ 114,101					$ 114,101
Retail Cost Variance Account - STR	1548	$ 173,008	$ 15,710	$ 188,718					$ 188,718
Misc. Deferred Debits	1525	$ 21,095	$ -	$ 21,095	$ -	$ 1,730	$ -	$ 322	$ 23,147
LV Variance Account (Note 1)	1550	$ (218,851)	$ (2,847)	$ (221,698)					$ 252,886
2006 PILs & Taxes Variance	1592	68,445	3,464	$ 71,909	$ (101,343)	$ (540)		$ (503)	$ (30,477)
RSVA - Power (excluding Global Adjustment)	1588	$ (5,582,213)	$ (667,465)	$ (6,249,678)					$ (6,249,678)
Recovery of Regulatory Asset Balances	1590	7,186,913	1,457,606	$ 8,644,519	$ (5,392,170)	$ 199,945	$ (1,927,904)	$ 13,031	$ 1,537,421
LRAM									$ 370,246
SSM									$ 1,279,685
Total Claim - ExG/Sc2/Tab3/pg1									$ (5,118,313)

Note (1)

EHM is requesting to recover $252,886 in forecasted Low voltage charges for the 2008 rate year through a rate rider.

This estimate is based on previous OEB Board approved LV recoveries.

Board Staff Technical Conference Question # 32

Reference: Board Staff Interrogatory No. 47

Please complete the following:

a. Missing interest rates used for account 1565 and 1566 on the table.
b. Prescribed rates were effective May 1, 2006 not Q2, 2006. Were the rates applied in May 1, 2006 or April 1, 2006
c. 1570 and 1571 were not included in the list.

Response: 32. a)

Interest Rates Used to Calculate Regulatory Deferral and Variance Accounts
For the Period from January 1, 2005 to Present
Board TQC # 32 (a)

	2005			-
Variance and Deferral Accounts & CWIP	**Q1**	**Q2**	**Q3**	**Q4**
Variance and Deferral Accounts				
1508 Other Regulatory Assets	5.75	5.75	5.75	5.75
1508 Other Regulatory Assets - Sub-account OEB Cost Assessments	5.75	5.75	5.75	5.75
1508 Other Regulatory Assets - Sub-account Pension Contributions	3.88	3.88	3.88	3.88
1518 Retail Cost Variance Account - Retail	6.90	6.90	6.90	6.90
1525 Miscellaneous Deferred Debits	6.90	6.90	6.90	6.90
1525 Miscellaneous Deferred Debits, Sub-account Payments to Customers	6.90	6.90	6.90	6.90
1548 Retail Cost Variance Account - STR	6.90	6.90	6.90	6.90
1550 LV Variance Account	6.90	6.90	6.90	6.90
1555 Smart Meter Capital and Recovery Offset Variance Account	-	-	-	-
1556 Smart Meter OM&A Variance Account	-	-	-	-
1562 Deferred Payments in Lieu of Taxes	6.90	6.90	6.90	6.90
1563 PILs contra account	6.90	6.90	6.90	6.90
1565 Conservation and Demand Management Expenditures and Recoveries	5.75	-	-	-

1566 CDM Contra	5.75	-	-	-
1570 Qualifying Transition Costs	6.90	-	-	-
1571 Pre-Market Opening Energy Variances Total	6.90	-	-	-
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	6.90	6.90	6.90	6.90
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	6.90	6.90	6.90	6.90
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	6.90	6.90	6.90	6.90
1586 Retail Settlement Variance Account - Retail Transmission Connection Charges	6.90	6.90	6.90	6.90
1588 Retail Settlement Variance Account - Power	6.90	6.90	6.90	6.90
1588 RSVA Power - Sub-account Global Adjustments	6.90	6.90	6.90	6.90
1590 Recovery of Regulatory Asset Balances	6.90	6.90	6.90	6.90
1592 2006 PILs and Taxes Variances	6.90	6.90	6.90	6.90
Construction Work in Progress Account	6.90	6.90	6.90	6.90
2055 Construction Work in Progress	6.90	6.90	6.90	6.90

Interest Rates Used to Calculate Regulatory Deferral and Variance Accounts
For the Period from January 1, 2005 to Present
Board TQC # 32 (a)

	2006			
Variance and Deferral Accounts & CWIP	**January -April 30, 2006**	**Effective May 1, 2006**	**Q3**	**Q4**
Variance and Deferral Accounts				
1508 Other Regulatory Assets	5.75	4.14	4.59	4.59
1508 Other Regulatory Assets - Sub-account OEB Cost Assessments	5.75	4.14	4.59	4.59
1508 Other Regulatory Assets - Sub-account Pension Contributions	3.88	4.14	4.59	4.59
1518 Retail Cost Variance Account - Retail	6.90	4.14	4.59	4.59
1525 Miscellaneous Deferred Debits	6.90	4.14	4.59	4.59
1525 Miscellaneous Deferred Debits, Sub-account Payments to Customers	6.90	4.14	4.59	4.59
1548 Retail Cost Variance Account - STR	6.90	4.14	4.59	4.59

1550 LV Variance Account	6.90		4.14	4.59	4.59
1555 Smart Meter Capital and Recovery Offset Variance Account	-		4.14	4.59	4.59
1556 Smart Meter OM&A Variance Account	-		4.14	4.59	4.59
1562 Deferred Payments in Lieu of Taxes	6.90		4.14	4.59	4.59
1563 PILs contra account	6.90		4.14	4.59	4.59
1565 Conservation and Demand Management Expenditures and Recoveries	-	-		-	-
1566 CDM Contra	-	-		-	-
1570 Qualifying Transition Costs	-	-		-	-
1571 Pre-Market Opening Energy Variances Total	-	-		-	-
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	6.90		4.14	4.59	4.59
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	6.90		4.14	4.59	4.59
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	6.90		4.14	4.59	4.59
1586 Retail Settlement Variance Account - Retail Transmission Connection Charges	6.90		4.14	4.59	4.59
1588 Retail Settlement Variance Account - Power	6.90		4.14	4.59	4.59
1588 RSVA Power - Sub-account Global Adjustments	6.90		4.14	4.59	4.59
1590 Recovery of Regulatory Asset Balances	6.90		4.14	4.59	4.59
1592 2006 PILs and Taxes Variances	6.90		4.14	4.59	4.59
Construction Work in Progress Account	6.90		4.14	4.59	4.59
2055 Construction Work in Progress	6.90		4.68	5.05	4.72

Interest Rates Used to Calculate Regulatory Deferral and Variance Accounts
For the Period from January 1, 2005 to Present
Board TQC # 32 (a)

	2007			
Variance and Deferral Accounts & CWIP	**Q1**	**Q2**	**Q3**	**Q4**
Variance and Deferral Accounts				
1508 Other Regulatory Assets	4.59	4.59	4.59	5.14

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments	4.59	4.59	4.59	5.14
1508 Other Regulatory Assets - Sub-account Pension Contributions	4.59	4.59	4.59	5.14
1518 Retail Cost Variance Account - Retail	4.59	4.59	4.59	5.14
1525 Miscellaneous Deferred Debits	4.59	4.59	4.59	5.14
1525 Miscellaneous Deferred Debits, Sub-account Payments to Customers	4.59	4.59	4.59	5.14
1548 Retail Cost Variance Account - STR	4.59	4.59	4.59	5.14
1550 LV Variance Account	4.59	4.59	4.59	5.14
1555 Smart Meter Capital and Recovery Offset Variance Account	4.59	4.59	4.59	5.14
1556 Smart Meter OM&A Variance Account	4.59	4.59	4.59	5.14
1562 Deferred Payments in Lieu of Taxes	4.59	4.59	4.59	5.14
1563 PILs contra account	4.59	4.59	4.59	5.14
1565 Conservation and Demand Management Expenditures and Recoveries	-	-	-	-
1566 CDM Contra	-	-	-	-
1570 Qualifying Transition Costs	-	-	-	-
1571 Pre-Market Opening Energy Variances Total	-	-	-	-
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	4.59	4.59	4.59	5.14
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	4.59	4.59	4.59	5.14
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	4.59	4.59	4.59	5.14
1586 Retail Settlement Variance Account - Retail Transmission Connection Charges	4.59	4.59	4.59	5.14
1588 Retail Settlement Variance Account - Power	4.59	4.59	4.59	5.14
1588 RSVA Power - Sub-account Global Adjustments	4.59	4.59	4.59	5.14
1590 Recovery of Regulatory Asset Balances	4.59	4.59	4.59	5.14
1592 2006 PILs and Taxes Variances	4.59	4.59	4.59	5.14
Construction Work in Progress Account	4.59	4.59	4.59	5.14
2055 Construction Work in Progress	4.72	4.72	5.18	5.18

a) **Enersource has added the missing interest rates for account 1565 and 1566 to the table. Please see the attached updated table #32 (a). Furthermore, an OEB Letter dated October 29, 2004, stated that interest was to be applied to CDM expenses incurred from July 1, 2004 to February 28, 2005 to the outstanding opening monthly balance in the deferral account. Carrying charges ceased after February 28, 2005. Enersource did not start spending until February 2005 and therefore interest did not apply to CDM spending after that date.**

b) **Enersource agrees that the prescribed interest rates were effective May 1, 2006 and not Q2 as was shown in the table and has updated the table #32 (a) to reflect correction. The prescribed interest rates were applied effective May 1, 2006.**

c) **1570 and 1571 were added to list in the table. Please see the attached updated table as for (a) above.**

- End of Document -

Enersource Mississauga Hydro Inc. (Enersource)
2008 Electricity Rate Application
Board File No. EB-2007-0706

SEC Clarifications

Question 1

Reference SEC I/R #4.

Please file these documents. We have accessed them, of course, but we need them on the record.

Question sent Friday Nov 23, 2:20 pm

[Ref: Exhibit J/Schedule D/page 6] Please file the audited financial statements and annual report as requested.

Response:

Please see attachments.

Consolidated Financial Statements of

ENERSOURCE CORPORATION

Years ended December 31, 2006 and 2005

KPMG

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AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Enersource Corporation as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Toronto, Canada

March 2, 2007

ENERSOURCE CORPORATION

Consolidated Balance Sheets
(In thousands of dollars)

December 31, 2006 and 2005

	2006	2005
Assets		
Current assets:		
Cash and cash equivalents	$ 56,871	$ 60,713
Accounts receivable	64,882	57,420
Unbilled revenue	51,311	64,530
Inventory	5,608	5,011
Assets held for sale (note 2)	–	1,484
Prepaid expenses and deposits	1,733	1,459
	180,405	190,617
Capital assets (note 4)	399,465	394,072
Assets held for sale (note 2)	–	22,490
Other assets:		
Deposits and prudentials (note 5)	21,740	22,354
Deferred debt issue costs, net of accumulated amortization of $2,458 (2005 - $2,024)	1,878	2,312
Regulatory assets (note 6)	12,179	21,014
	35,797	45,680
	$ 615,667	$ 652,859
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 81,094	$ 118,640
Payments in lieu of corporate income taxes payable	3,093	6,673
Deferred revenue	319	2,347
Advance payments	1,757	629
Regulatory liabilities (note 6)	5,283	8,678
	91,546	136,967
Long-term liabilities:		
Bonds payable (note 7)	290,000	290,000
Deposits	21,740	22,354
Employee retirement and post-retirement benefits (note 8)	2,656	2,140
	314,396	314,494
Non-controlling interest	194	193
Shareholders' equity:		
Capital stock (note 9)	175,691	175,691
Retained earnings	33,840	25,514
	209,531	201,205
Contingencies (note 11)		
Commitments (notes 5 and 12)		
	$ 615,667	$ 652,859

See accompanying notes to consolidated financial statements.

On behalf of the Board:

________________ Director ________________ Director

ENERSOURCE CORPORATION

Consolidated Statements of Income
(In thousands of dollars)

Years ended December 31, 2006 and 2005

	2006	2005
Revenue:		
Energy sales	$ 557,271	$ 672,412
Distribution	104,120	95,982
Recovery of regulatory assets	7,144	7,513
Services	8,829	11,814
Gain (loss) on the disposal of capital assets	720	(191)
Other	2,234	2,461
	680,318	789,991
Operating expenses:		
Energy purchases	557,271	672,412
Operations, maintenance and administration	40,378	34,120
Services	6,561	8,687
Amortization of capital assets	30,285	29,771
Amortization of regulatory assets	7,144	7,513
	641,639	752,503
Operating income	38,679	37,488
Interest:		
Income	3,164	1,915
Expense	(18,595)	(17,691)
	(15,431)	(15,776)
Income before the undernoted	23,248	21,712
Payments in lieu of corporate income taxes (note 3)	(9,938)	(9,018)
Income from continuing operations	13,310	12,694
Income from discontinued operations, net of payments in lieu of corporate income taxes (note 2)	3,916	726
Net income	$ 17,226	$ 13,420

Consolidated Statements of Retained Earnings
(In thousands of dollars)

Years ended December 31, 2006 and 2005

	2006	2005
Retained earnings, beginning of year	$ 25,514	$ 20,994
Net income	17,226	13,420
Dividends paid (note 9)	(8,900)	(8,900)
Retained earnings, end of year	$ 33,840	$ 25,514

See accompanying notes to consolidated financial statements.

ENERSOURCE CORPORATION

Consolidated Statements of Cash Flows
(In thousands of dollars)

Years ended December 31, 2006 and 2005

	2006	2005
Cash provided by (used in):		
Operating activities:		
Income from continuing operations	$ 13,310	$ 12,694
Items not affecting cash:		
Amortization of debt issue costs	434	434
Amortization of capital assets	30,285	29,771
Amortization of regulatory assets	7,144	7,513
Loss (gain) on disposal of capital assets	(720)	191
Employee retirement and post-retirement benefits	516	91
	50,969	50,694
Change in non-cash operating working capital (note 10)	(38,110)	26,598
	12,859	77,292
Financing activities:		
Deposits	(614)	(5,766)
Dividends paid	(8,900)	(8,900)
	(9,514)	(14,666)
Investing activities:		
Deposits and prudentials	614	5,766
Additions to capital assets	(35,892)	(30,245)
Proceeds on disposal of capital assets	25,136	86
Decrease (increase) to regulatory assets	1,711	(4,162)
	(8,431)	(28,555)
Increase (decrease) in cash and cash equivalents from continuing operations	(5,086)	34,071
Discontinued operations	1,244	134
Increase (decrease) in cash and cash equivalents	(3,842)	34,205
Cash and cash equivalents, beginning of year	60,713	26,508
Cash and cash equivalents, end of year	$ 56,871	$ 60,713
Supplemental cash flow information:		
Interest received	$ 3,618	$ 1,903
Interest paid	18,241	18,241
Payments in lieu of corporate income taxes paid	16,040	7,046

See accompanying notes to consolidated financial statements.

Enersource Corporation (the "Corporation"), incorporated under the Ontario Business Corporations Act, was formed to conduct electricity distribution, and operate fibre optic and non-regulated utility service ventures. It is owned 90% by the City of Mississauga (the "City") and 10% by BPC Energy Corporation ("BPC"), a wholly owned subsidiary of the Ontario Municipal Employees Retirement System ("OMERS").

1. Significant accounting policies:

(a) Basis of consolidation:

These financial statements have been prepared by management in accordance with generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of the Corporation's wholly owned subsidiaries: Enersource Hydro Mississauga Inc. ("Enersource Hydro"), Enersource Services Inc., Enersource Telecom Inc., Enersource Technologies Inc. and Enersource Hydro Mississauga Services Inc. The consolidated financial statements also include the accounts of First Source Energy Corporation ("First Source"), a subsidiary in which the Corporation has a 57.7% ownership interest. Intercompany balances and transactions have been eliminated.

(b) Nature of operations:

Through its subsidiary, Enersource Hydro, the Corporation provides electricity distribution services to businesses and residences in the service area of Mississauga, Ontario.

Enersource Services Inc. is the parent company for the Corporation's non-regulated business, which includes the following:

(i) Enersource Telecom Inc. provided fibre optic telecommunications services for customers located in Ontario until May 2006 (note 2), at which point its fibre optic infrastructure assets and related customer contracts were sold to Blink Communications.

(ii) Enersource Hydro Mississauga Services Inc. provides utility services, including safety training and energy settlement services, specialized construction and streetlight construction and maintenance services to customers in Ontario. Enersource Hydro Mississauga Services Inc. is also the 100% owner of Enersource Technologies Inc., which is a dormant corporation.

1. Significant accounting policies (continued):

(iii) First Source provided ongoing energy retailing services until May 2003 (note 2), at which point, its retail customer contracts were sold to Ontario Energy Savings Corporation ("OESC").

(iv) Golden Horseshoe Metering Systems Inc. had been formed to supply and install smart meters in multi-unit residential buildings throughout Ontario. On December 31, 2006, Enersource Hydro Mississauga Services Inc. sold its shares in the joint venture to Oakville Hydro Energy Services. Enersource Hydro Mississauga Services Inc. did not record any economic benefit from the joint venture or share divestiture.

(c) Rate setting:

Enersource Hydro is regulated by the Ontario Energy Board ("OEB") under authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in the change in the timing of accounting recognition from that which would be applied in an unregulated company. Specifically, the following accounting treatments have been applied:

(i) Capital and operating costs incurred in respect of the transition to competitive markets have been deferred with amortization to commence at a date that a rate increase is implemented to offset the amortization of the transition costs. In November 2003, the Province of Ontario introduced the Ontario Energy Board Amendment Act (Electricity Pricing) 2003 (the "2003 Act"). The 2003 Act impacts both distribution and energy rates charged to customers and include a provision for the recovery of regulatory assets (note 1(l)). As of April 1, 2004, the Corporation commenced recovery of these deferred transition costs in accordance with the 2003 Act.

(ii) An amount to represent the cost of funds used during construction and development has been applied based on the value of construction in progress.

(iii) The Corporation does not record future income tax assets or liabilities for its regulated business activities to the extent that it is expected that the recovery or realization of these amounts will be included in future distribution rates.

1. Significant accounting policies (continued):

(iv) The Corporation has deferred certain pre-market opening cost of power variances and post-market opening retail settlement variances in accordance with Article 490 of the OEB's Accounting Procedures Handbook.

(v) The Corporation has deferred the recognition of the employer's share of contributions to OMERS for its regulated business activities from January 1, 2004 to April 30, 2006. As of May 1, 2006, the Corporation commenced recovery of the 2004 portion with the remainder expected to be recovered through future distribution rates.

(d) Cash and cash equivalents:

Cash and cash equivalents are defined as cash and bank term deposits or equivalent financial instruments with original maturities upon issue of less than 90 days.

(e) Revenue recognition:

Distribution revenue attributable to the delivery of electricity is based upon OEB-approved distribution tariff rates and is recognized as electricity is delivered to customers, which includes an estimate of unbilled revenue, which represents electricity consumed by customers since the date of each customer's last meter reading. Actual electricity usage could differ from estimates.

Services and other revenue is recognized as services are rendered or contract milestones are achieved. Amounts received in advance of these milestones are presented as deferred revenue.

(f) Measurement uncertainty:

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the years. Accounts receivable is reported based on amounts expected to be recovered less an appropriate allowance for unrecoverable amounts based on prior experience. Unbilled revenue and regulatory assets are reported based on amounts expected to be recovered. Inventories are recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful life.

1. Significant accounting policies (continued):

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these consolidated financial statements, including changes as a result of future decisions made by the OEB or the Minister of Energy.

(g) Inventory:

Inventory, which consists of parts and supplies acquired for internal construction or consumption, is valued at the lower of cost and replacement cost. Cost is determined on a weighted moving average basis.

(h) Capital assets:

Capital assets are recorded at cost and include contracted services, materials, labour, engineering costs, overheads and an allowance for the cost of funds used during construction when applied. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers.

When assets are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in the operating results for the related fiscal period. The cost and related accumulated amortization of grouped assets, such as transmission and distribution facilities, is removed from the accounts at the end of their estimated service lives.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

1. Significant accounting policies (continued):

Amortization of capital asset values is charged to operations on a straight-line basis over their estimated service lives as follows:

	Estimated service life Range	Average
Buildings	25 - 60 years	54
Distribution station equipment	15 - 35 years	29
Transmission and distribution system	25 - 40 years	26
Equipment and furniture	4 - 10 years	8
Computer software	2 years	2

Amortization is recorded at one-half the usual annual rate for assets placed into service in the current fiscal period.

Construction in progress comprises capital assets under construction, assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed.

An allowance for the cost of funds used during the construction period has been applied. The rate applied for the 2005 year and the period from January through April 2006 was 6.9% as allowed by the OEB. Effective May 1, 2006, the prescribed interest rate used during the period equals the Scotia Capital Inc. mid-term all corporate average weighted yield, as published on the Bank of Canada's website, updated quarterly. From May 1, 2006 to June 30, 2006, the rate used was 4.68%. From July 1, 2006 to September 30, 2006, the rate used was 5.05%. From October 1, 2006 to December 31, 2006, the rate used was 4.72%.

(i) Deferred debt issue costs:

Deferred debt issue costs represent the cost of the issuance of the bonds. Amortization is provided on a straight-line basis over the term of the related bonds.

1. Significant accounting policies (continued):

(j) Deposits and prudentials:

Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as deposits and prudentials, which are reported separately from the Corporation's own cash and cash equivalents. Interest rates paid on customer deposits are based on a variable rate of prime less 2.0%, updated quarterly.

Also included in this balance are cash and securities lodged with the Corporation by counterparties under electricity supply agreements.

(k) Pension and other post-employment benefits:

The Corporation accounts for its participation in OMERS, a multi-employer public sector pension fund, as a defined contribution plan. The Corporation obtained approval from the OEB to defer pension expenses incurred from January 1, 2004 to April 30, 2006 in the regulated utility. Effective May 1, 2006, the Corporation commenced recognition of expenses related to contributions to OMERS.

The Corporation actuarially determines the cost of other employment and post-employment benefits offered to employees using the projected benefit method, prorated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefit is deemed to be earned on a pro rata basis over the years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits.

(l) Regulatory assets and liabilities:

Regulatory assets primarily represent costs that have been deferred because they are expected to be recovered in rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers under the regulated pricing mechanism and the corresponding wholesale market cost of power incurred by the utility. The OEB directed the distribution utilities to recover these variance balances as at December 31, 2003 plus accrued interest in the rates over a four-year period beginning April 2004.

1. Significant accounting policies (continued):

Regulatory balances are comprised principally as follows:

(i) Transition costs - represent costs related to the transition to a competitive electricity market, mandated by the Electricity Act, 1998. The OEB has established rules in respect of transition costs, to qualify amounts for deferral and amortization against future revenue. Enersource Hydro's transition costs have been reviewed via an oral hearing and recovery has been decided upon by the OEB in its December 9, 2004 decision.

(ii) Pre-market opening cost of power variances - represents amounts accumulated as a result of the excess of the cost of power purchased by the Corporation over the amount billed for this power prior to the market opening. The OEB directed utilities to accumulate such variances in the period leading up to market opening.

(iii) Post-market opening retail settlement variances - are variances that have occurred since May 1, 2002, when the competitive electricity market was declared open and that have accumulated pursuant to direction from the OEB. Specifically, these amounts include variances between the amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the markets and grid, as well as various wholesale market settlement charges and transmission charges as compared to the amount billed to consumers based on the OEB-approved rates.

(iv) All revenue and associated costs for the smart meter program have been deferred as directed by the OEB in their April 12, 2006 rate decision.

In November 2003, the Province of Ontario introduced the 2003 Act, which implemented a new electricity pricing regime believed to better reflect the true cost of electricity.

1. Significant accounting policies (continued):

The 2003 Act, which received Royal Assent in December 2003, removed the $0.043/kWh electricity price freeze established under the Electricity Pricing, Conservation and Supply Act, 2002 and gives the OEB the power to establish the electricity commodity price for low volume consumers and designated consumers who do not choose an electricity retailer. On April 1, 2004, the government implemented an interim pricing plan under which the first 750 kWh consumed in any month by low volume and designated consumers was priced at $0.047/kWh and consumption above that level for these consumers was priced at a higher rate of $0.055/kWh. On April 1, 2005, electricity prices increased from $0.047/kWh to $0.050/kWh for the first 750 kWh consumed in a month, and from $0.055/kWh to $0.058/kWh for consumption in excess of that amount. In the event that these interim prices exceeded the costs paid by the Ontario Electricity Financial Corporation ("OEFC"), the 2003 Act included a provision permitting the making of regulations requiring distributors, retailers or the IESO to credit consumers for the difference. Under the 2003 Act, regulations may also be made to compensate distributors, retailers and the IESO for making any such payments.

In November 2003, the Province of Ontario announced its intention to allow electricity distributors to recover deferred transition costs and energy variances over a four-year period commencing April 1, 2004. In January 2004, in compliance with regulatory direction, Enersource Hydro submitted to the OEB an application to recover 25% of the December 31, 2002 balance of these regulatory assets. On December 9, 2004, the OEB awarded Enersource Hydro $26,700 for the recovery of regulatory balances as at December 31, 2003, plus interest, as determined by a Regulatory Hearing.

On April 1, 2005, Enersource Hydro implemented the final rate increase, as permitted by the OEB, toward achieving a market-based rate of return. The initial 12 months of this incremental revenue will be fully invested in electricity conservation and demand management strategies by September 2007.

On April 12, 2006, the OEB announced further changes to electricity prices for regulated price plan customers to take effect May 1, 2006. Electricity prices increased effective May 1, 2006 from $0.050/kWh to $0.058/kWh for the first 600 kWh consumed in a month and from $0.058/kWh to $0.067/kWh for consumption in excess of that amount. The price threshold is 600kWh for the period from May 1 through October 31 and 1,000 kWh per month during the period from November 1 through April 30. The threshold for non-residential customers that are eligible for the regulated price plan will remain at 750 kWh per month throughout the year.

1. Significant accounting policies (continued):

On October 11, 2006, the OEB announced further changes to electricity prices for regulated price plan customers to take effect November 1, 2006. Electricity prices decreased effective November 1, 2006 from $0.058/kWh to $0.055/kWh for the first 1,000 kWh consumed in a month and from $0.067/Kwh to $0.064/kWh for consumption in excess of that amount. These prices will be adjusted every six months by the OEB as required.

In August 2005, Enersource Hydro submitted a rate application to the OEB for the rate period beginning May 1, 2006 and ending on April 30, 2007. This rate application proposes the full re-basing of Enersource Hydro's electricity distribution rates to more accurately reflect Enersource Hydro's current rate base and cost structure. On April 12, 2006, the OEB released its decision and order regarding Enersource Hydro's rate application. This decision allows for a distribution rate increase of approximately 2.3% on the total bill of an average residential customer using 1,000 kWh per month. The decision also allows for a newly introduced rate increase for smart meters.

On June 12, 2006, Enersource Hydro submitted a review and vary motion to the OEB to revise its approved 2006 tariff of rates and charges. On October 3, 2006, the OEB released its final decision regarding this motion. The decision allows for additional expense recoveries of $1,152 annually and a $2,714 adjustment to dispose of the liability balances recorded in Enersource Hydro's retail settlement variance accounts, as of December 31, 2004, over a two-year period.

(m) Payments in lieu of corporate income taxes:

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate income taxes ("PILs") to OEFC. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario), as modified by the Electricity Act, 1998, and related regulations.

The Corporation provides for PILs related to its regulated business using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes.

Management believes that when unrecorded future income taxes become payable, or the assets are realized, it is expected that they will be included in rates approved by the OEB and recovered from customers at that time.

1. Significant accounting policies (continued):

For its non-regulated businesses, the Corporation applies the asset and liability method of accounting for income taxes. Under the asset and liability method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

2. Discontinued operations:

During the second quarter of 2003, the Corporation's Board of Directors approved the sale of the retail customer contracts of First Source. This sale closed on May 1, 2003. On January 23, 2006, Enersource Hydro Mississauga Services Inc. closed a transaction for the sale of its water heaters and associated customer rental contracts. On May 24, 2006, Enersource Telecom Inc. finalized the sale of its fibre optic infrastructure and related customer contracts.

These consolidated financial statements have adopted the recommendation of The Canadian Institute of Chartered Accountants' ("CICA") Handbook Section 3475, Disposal of Long-lived Assets and Discontinued Operations ("Section 3475").

(a) Income from discontinued operations:

The income from discontinued operations, net of payments in lieu of corporate income taxes for 2006 of $3,916 (2005 - $726) is made up of the Corporation's 57.7% interest in First Source's net income, Enersource Telecom Inc.'s net income and net income from Enersource Hydro Mississauga Service Inc.'s water heaters ("Water Heaters").

	2006	2005
First Source (57.7% interest)	$ 18	$ 12
Enersource Telecom Inc.	3,837	118
Water Heaters	61	596
Income from discontinued operations, net of payments in lieu of corporate income taxes	$ 3,916	$ 726

2. Discontinued operations (continued):

(b) Net assets of First Source:

	2006	2005
Cash	$ 579	$ 740
Accounts receivable	2	–
Other non-current assets	1	1
Accounts payable and accrued liabilities	(123)	(282)
Net assets of discontinued operations	$ 459	$ 459
Non-controlling interest in subsidiary	$ 194	$ 193

(c) Assets held for sale:

In an effort to focus resources on its core energy businesses, agreements were reached to sell certain assets within Enersource Telecom Inc. and Water Heaters. Results from these operations have been disclosed as discontinued operations for both 2006 and 2005 and the assets that were sold have been disclosed as assets held for sale on the consolidated balance sheet for 2005 as prescribed in Section 3475 in the CICA Handbook. A summary of the assets and liabilities that were held for sale is as follows:

Assets held for sale - current:

	2006	2005
Water Heaters:		
Inventory	$ –	$ 16
Capital assets	–	1,468
	$ –	$ 1,484

Assets held for sale - long-term:

	2006	2005
Enersource Telecom Inc.:		
Inventory	$ –	$ 205
Prepaid expenses and deposits	–	67
Capital assets	–	22,288
Deferred revenue	–	(70)
	$ –	$ 22,490

2. Discontinued operations (continued):

Water Heaters:

The transaction to sell over 12,000 electric water heater customer contracts, rental agreements and related assets to Union Energy Limited Partnership closed on January 23, 2006. Included in the gain (loss) on the disposal of capital assets is a gain of $2,592 resulting from this asset sale transaction. A holdback of $139 by Union Energy Limited Partnership is outstanding and has not been reflected in the calculation of the gain, but has been deferred until a final settlement can be reached.

Enersource Telecom Inc. assets:

A separate agreement was finalized to sell specific Enersource Telecom Inc. assets on May 24, 2006 to Blink Communications. Included in the gain (loss) on the disposal of capital assets is a loss of $1,958 resulting from this asset sale transaction. As at December 31, 2006, all terms and conditions of the sale agreement have been satisfied.

3. Payments in lieu of corporate income taxes:

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

	2006	2005
Federal and Ontario statutory income tax rate	36.12%	36.12%
Income before provision for PILs	$ 23,248	$ 21,712
Income from discontinued operations	3,951	1,086
	$ 27,199	$ 22,798
Provision for PILs at statutory rate	$ 9,824	$ 8,235
Increase (decrease) resulting from:		
Amortization less than capital cost allowance	143	361
Tax effect of non-capital losses for which no benefit has been recorded	(1,395)	568
Recovery of regulatory assets for accounting purposes in excess of recovery for tax purposes	1,401	(620)
Large Corporations Tax	–	834
PILs on discontinued operations	(35)	(360)
Provision for PILs	$ 9,938	$ 9,018
Effective income tax rate	36.5%	41.1%

Based on substantively enacted income tax rates, the potential benefit of unrecorded future income tax assets arising substantially from differences between accounting and tax values for capital assets of the regulated business is $37,515 (2005 - $43,923). Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenue.

The Corporation does not have any significant future income tax assets or liabilities arising from the non-regulated businesses.

3. Payments in lieu of corporate income taxes (continued):

At December 31, 2006, certain other subsidiaries have non-capital loss carryforwards totalling $14,665 (2005 - $12,401) available, which will expire after tax years ending between 2008 and 2015. The potential benefit relating to these amounts has not been recorded given the uncertainty as to their realization.

4. Capital assets:

2006	Cost	Accumulated amortization	Net book value
Land	$ 4,071	$ –	$ 4,071
Buildings	14,575	4,755	9,820
Distribution station equipment	78,153	32,018	46,135
Transmission and distribution system	591,568	274,117	317,451
Equipment and furniture	25,839	14,027	11,812
Computer software	2,919	1,207	1,712
Construction in progress:			
Buildings	34	–	34
Electric distribution system	8,341	–	8,341
Equipment and furniture	89	–	89
	$ 725,589	$ 326,124	$ 399,465

2005	Cost	Accumulated amortization	Net book value
Land	$ 4,071	$ –	$ 4,071
Buildings	14,065	4,462	9,603
Distribution station equipment	78,168	33,970	44,198
Transmission and distribution system	571,056	253,593	317,463
Equipment and furniture	23,632	13,244	10,388
Computer software	2,236	1,200	1,036
Construction in progress:			
Buildings	1	–	1
Electric distribution system	7,312	–	7,312
	$ 700,541	$ 306,469	$ 394,072

During the year, $406 (2005 - $438), representing an allowance for the cost of funds used during construction, was capitalized to construction in progress.

5. Deposits and prudentials:

The following outlines the deposits and prudentials of the Corporation, posted as security. The amounts are comprised of cash and cash equivalents in the form of deposits and letters of credit/letters of guarantee, under which the Corporation is contingently liable.

	2006		2005	
	Cash and cash equivalents	Letters of credit/ letters of guarantee	Cash and cash equivalents	Letters of credit/ letters of guarantee
Customer deposits	$ 21,740	$ –	$ 22,354	$ –
Supplier deposits	–	–	–	3,000
Security with IESO	–	16,618	–	16,618
	$ 21,740	$ 16,618	$ 22,354	$ 19,618

Security deposits:

(a) Customer deposits:

The Corporation collects cash and cash equivalents as deposits from certain customers to reduce credit risk.

Contingent obligations:

(b) Supplier deposits:

The Corporation's financial energy supply contracts were formed based on the International Swap Dealers Association ("ISDA") templates. Counterparty agreements dictate the method, nature and calculation of various credit-related positions.

At December 31, 2006, the Corporation had a letter of credit guarantee from OESC of $1,600 (2005 - $1,600) in respect of the Corporation's requirement to post parental guarantees and no longer had a parental guarantee with Ontario Power Generation Corporation (2005 - $3,000).

In accordance with the Shareholders' Agreement, the Corporation is liable for 57.7% of the parental guarantee to Ontario Power Generation Corporation, with Veridian Corporation liable for the remaining 42.3%.

5. Deposits and prudentials (continued):

(c) Margin calls:

In accordance with the ISDA contracts between the counterparties, margin calls can be initiated when forward market prices change.

Forward market prices are monitored weekly by the Corporation to ensure that margin calls are anticipated in advance as the forward price approaches the trigger rate. The Corporation places a margin call on OESC in response to reaching the forward pricing trigger rate and OESC indemnifies the cash collateral obligation of the Corporation.

(d) Security with IESO:

Purchasers of electricity in Ontario through the IESO are required to post security to mitigate the risk of their default on their expected activity in the market.

At December 31, 2006, the Corporation has posted a letter of credit as security in the amount of $16,618 (2005 - $16,618).

6. Regulatory assets and liabilities:

Regulatory assets and liabilities can arise as a result of the rate-making process. The following table demonstrates the impact on 2006 earnings net of PILs as a result of regulated accounting requirements.

	2006	2005	Estimated remaining settlement period (years)	2006 impact on earnings net of PILs ((a)(i))
Regulatory assets:				
Deferred OMERS employer contributions ((a)(ii))	$ 1,372	$ 1,916	1 - 2	$ (331)
Other regulatory assets ((a)(iii))	1,549	1,436	1 - 2	(702)
Smart meter revenue/expense ((a)(iv))	(268)	–	4	268
	2,653	3,352		(765)
Regulatory assets approved for recovery ((a)(v))	9,526	17,662	2 - 3	3,454
	$ 12,179	$ 21,014		$ 2,689
Regulatory liabilities:				
Retail settlement variances ((a)(vi))	$ 11,996	$ 2,276	1	$ 491
Global adjustment retail settlement variance ((a)(vii))	(6,713)	6,402	1	(174)
	$ 5,283	$ 8,678		$ 317

(a) Explanatory notes:

(i) The 2006 impact on earnings net of PILs represents the effect on the consolidated net income as a result of the treatment under rate regulated accounting.

(ii) The OEB had approved the deferral of Enersource Hydro's employer portion of pension contributions to OMERS retirement fund. The deferred OMERS employer contributions amount reflects Enersource Hydro's required contributions between January 1, 2004 and April 30, 2006 plus interest charged at an OEB approved rate less amounts recovered through distribution rates since May 1, 2006.

6. **Regulatory assets and liabilities (continued):**

(iii) The OEB requires that Enersource Hydro record and defer the difference between revenue and costs associated with providing retailers with customer settlement services as retail cost variance account deferrals and had approved the deferral of Enersource Hydro's OEB assessed costs between January 1, 2004 and April 30, 2006. These items are included in other regulatory assets.

(iv) On June 13, 2006, the OEB issued an update to the accounting procedure handbook regarding the accounting treatment for smart meter expenditures. This amount reflects the net amount of revenue and expenses deferred since May 1, 2006.

(v) On December 9, 2004, the OEB approved the recovery of Enersource Hydro's regulatory assets as at December 31, 2003. On October 3, 2006, the OEB approved the disposition of Enersource Hydro's retail settlement variance accounts, as of December 31, 2004. This amount reflects the total approved regulatory assets for recovery plus interest charged at an OEB approved rate less amounts recovered through distribution rates since April 1, 2004.

(vi) The OEB requires Enersource Hydro to record and defer the difference between energy charged to its customers and the actual cost of power incurred and paid to the IESO and to Hydro One. The retail settlement variance reflects this difference since January 1, 2005 plus interest charged at an OEB approved rate.

(vii) The Global Adjustment account accounts for the difference between market prices and rates paid to regulated and contracted generators which are set by the IESO. This adjustment may be positive or negative. The Global Adjustment retail settlement variance captures the unpaid or recoverable amounts due to or recoverable from Enersource Hydro's customers.

The Corporation has accrued interest on the deferral account balances for the regulatory assets and retail settlement variances, as directed by the OEB. As at December 31, 2006, this net accrued interest amounted to $413 (2005 - $1,022).

6. Regulatory assets and liabilities (continued):

(b) Financial statement effects of rate regulation:

(i) General information regarding rate regulation and its economic effects:

The operations of the Corporation's subsidiary, Enersource Hydro, are regulated by the OEB. The OEB exercises statutory authority over matters such as construction, rates and underlying accounting practices, and rate setting issues with Enersource Hydro's customers.

On April 12, 2006, Enersource Hydro's rate application was approved by the OEB for the rate period beginning May 1, 2006 and ending on April 30, 2007. These rates are set by the OEB under a cost of service methodology that allows revenue to recover utility operating costs plus a regulated rate of return on the equity financed portion of Enersource Hydro's rate base. The allowed rate of return for this rate period is set by the OEB at 9.0%.

(ii) Regulatory risk and uncertainties affecting recovery or settlement:

The regulatory assets and liabilities recorded in the consolidated financial statements are based upon an expectation of the future actions of the OEB. To the extent that the OEB's future actions are different from Enersource Hydro's expectations, the timing and amount of recovery or settlement of amounts recorded on the consolidated balance sheets could be significantly different from the timing and amounts that are eventually recovered or settled.

(iii) Financial statement effects:

In order to recognize the economic effects of the actions or expected actions of the regulator, the timing of recognition of certain revenue and expenses in these operations may differ from that otherwise expected under GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through the rate setting process. In the absence of rate regulated accounting, GAAP would not permit deferral of regulatory assets and, therefore, the earnings impact would be recorded in the period of recovery. Long-term regulatory assets are recorded in other assets in the consolidated balance sheets.

6. Regulatory assets and liabilities (continued):

Regulatory liabilities represent amounts that are expected to be refunded to customers as a result of the rate-setting process. The GAAP treatment of regulatory liabilities and the resulting earnings impact is the same as that under rate regulated accounting because the liabilities represent contractual obligations. Regulatory liabilities are recorded in current liabilities in the consolidated balance sheets.

(c) Other items affected by rate regulation:

Future income taxes:

Enersource Hydro's regulated activities recover tax expense based on the taxes payable method as prescribed by the OEB. As such, the rates approved by the OEB do not include the recovery of future income taxes related to temporary differences. Consequently, the financial statements pertaining to the regulated operations do not record future income taxes as the future income taxes will be recovered in future rates when they become payable. GAAP requires the recognition of future income tax liabilities and future income tax assets in the absence of rate regulation.

7. Bonds payable:

	2006	2005
6.29% BPC-Enersource Series Bonds, Tranche 1, due May 3, 2011	$ 290,000	$ 290,000

Interest expense includes $18,241 (2005 - $18,241) in respect of interest on long-term liabilities and amortization of debt issue costs in the amount of $434 (2005 - $434).

8. Employee retirement and post-retirement benefits:

(a) Pensions:

During fiscal 2006, the Corporation made contributions of $2,021 (2005 - $1,728). With the OEB's approval, the Corporation has deferred $331 (2005 - $1,042) of its 2006 pension expense in the regulated utility for recovery in future rates.

(b) Other retirement and post-retirement benefits:

The Corporation presently offers two separate retirement and post-retirement benefit plans. The total employee retirement and post-retirement benefits liability for the two plans as at December 31, 2006 was $2,656. The amounts presented are based upon an actuarial valuation performed as of December 31, 2006 on March 2, 2007. The next valuation is expected to be performed for the year ending December 31, 2009.

(c) Retirement and post-retirement life benefits:

(i) Accrued benefit obligation:

	2006	2005
Accrued benefit obligation, beginning of year	$ 2,140	$ 2,049
Service cost	81	32
Interest cost	122	133
Benefits paid	(70)	(74)
Unrecognized actuarial loss	138	–
Accrued benefit obligation, end of year	$ 2,411	$ 2,140

(ii) Reconciliation of accrued benefit obligation to balance sheet liability:

	2006	2005
Accrued benefit obligation, end of year	$ 2,411	$ 2,140
Unrecognized actuarial loss	(138)	–
Post-employment benefits liability	$ 2,273	$ 2,140

8. Employee retirement and post-retirement benefits (continued):

(iii) Significant assumptions:

	2006	2005
Discount rate	5.25%	6.50%
Rate of compensation increase	2.50%	3.00%

The principal funding obligation of the plan is to fund life insurance benefits based on employment date and years of service. A limited group of former employees who elected to retire under a special early retirement incentive plan is entitled to continuation of health and dental premiums at their own expense, until age 65. Accordingly, based on the current participation profile, changes in health and dental care costs will not significantly impact the estimates of the plan obligations. Net actuarial gains or losses over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the expected average remaining service lifetime. The total post-employment benefits liability at December 31, 2006 is $2,273 (2005 - $2,140). There are no transition obligations to be amortized from past services.

A 1% increase (decrease) in the interest assumption would decrease (increase) the post-retirement benefit obligation and the service cost by approximately 14% to 16%.

The Corporation's net life insurance benefit expense is as follows:

	2006	2005
Current service cost	$ 81	$ 32
Interest cost	122	133
	$ 203	$ 165

8. Employee retirement and post-retirement benefits (continued):

(d) Retirement and post-retirement health and dental benefits:

(i) Accrued benefit obligation:

	2006	2005
Change in benefit obligations:		
Benefit obligation, beginning of year	$ –	$ –
Service cost	138	–
Amortization of transition obligation	167	–
Interest cost	79	–
Benefits paid	(1)	–
Transition obligation	1,333	–
Actuarial losses	176	–
Accrued benefit obligation, end of year	$ 1,892	$ –

(ii) Reconciliation of accrued benefit obligation to balance sheet liability:

	2006	2005
Benefit obligation, end of year	$ 1,892	$ –
Unrecognized transition obligation	(1,333)	–
Unrecognized actuarial loss	(176)	–
Post-employment benefits liability	$ 383	$ –

(iii) Significant assumptions:

	2006	2005
Discount rate	5.25%	–
Expected return on plan assets	5.25%	–
Health care cost increases	15.00%	–
Dental cost increases	5.00%	–

8. Employee retirement and post-retirement benefits (continued):

The Corporation's net health and dental benefit expense is as follows:

	2006	2005
Amortization of transition obligation	$ 167	$ –
Current service cost	138	–
Interest cost	79	–
	$ 384	$ –

The principal funding obligation of the plan is to fund health and dental benefits to those employees who retire on or after age 55 with at least 10 years of service with a specified cost sharing formula for participation from the time of early retirement to age 65. Net actuarial gains or losses over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the expected average remaining service lifetime. The total post-employment benefits liability at December 31, 2006 is $383 (2005 - nil). The unrecognized transition obligation will be amortized over the expected average remaining service lifetime.

For December 31, 2006, health care costs were assumed to increase by 15%, then grading down to 4% per annum after 10 years. Dental costs were assumed to increase by 5% in 2006, then grading down to 3% per annum after 10 years.

A 1% increase (decrease) in the interest assumption would decrease (increase) the expected post-retirement benefit obligation, the interest cost and the service cost by approximately 10%.

9. Capital stock:

	2006	2005
Authorized:		
Unlimited Class A shares, voting		
1,000 Class B shares, non-voting		
100 Class C shares, voting		
Issued:		
180,555,562 Class A shares	$ 155,628	$ 155,628
1,000 Class B shares	1	1
100 Class C shares	20,062	20,062
	$ 175,691	$ 175,691

9. Capital stock (continued):

On November 9, 2004, the Corporation adopted the Dividend Policy and Procedure document that was approved by the Board of Directors. Subsequently, the Articles of the Corporation were amended in 2005 to align with the terms of the Dividend Policy.

The Class A and Class C shareholders are entitled to annual non-cumulative dividends not to exceed 60% of the prior year's consolidated after-tax net income on a residual basis. Dividends will be declared and paid during the fourth quarter of each fiscal year; provided they are approved by a Board resolution and all compliance issues have been addressed.

In 2006, a dividend of $8,900 (2005 - $8,900) was declared and paid to the shareholders.

The shareholders of the Corporation are parties to a Put Agreement by which the City holds an option to sell its shares to BPC in accordance with the Agreement. The effective period for this option commences July 1, 2008 and expires on December 31, 2008.

10. Change in non-cash operating working capital:

	2006	2005
Accounts receivable	$ (8,141)	$ (6,179)
Unbilled revenue	13,219	(13,284)
Inventory	(376)	(702)
Prepaid expenses and deposits	(212)	(571)
Accounts payable and accrued liabilities	(36,639)	42,282
Payments in lieu of corporate income taxes payable	(3,524)	5,268
Deferred revenue	(170)	387
Advance payments	1,128	(1,100)
Regulatory liabilities	(3,395)	497
	$ (38,110)	$ 26,598

11. Contingencies:

(a) Insurance claims:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousand dollars of service revenue subject to a credit or surcharge based on each member's claims experience. Current liability coverage is provided to a level of $30,000 per incident.

Enersource Hydro has been jointly named as a defendant in several actions. No provision has been made for these potential liabilities as Enersource Hydro expects that these claims are adequately covered by its insurance.

(b) Other claims:

A class action claiming $500,000 in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against the former Toronto Hydro-Electric Commission as the representative of the Defendant Class, consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Corporation. It is the Corporation's position that any late payment charges that are required to be repaid to customers as a result of this class action would be included in a rate adjustment application to the OEB for full recovery.

11. Contingencies (continued):

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against Enbridge Gas Distribution ("EGD") with respect to late payment penalties. At the end of 2006, a mediation process resulted in the settlement of the damages payable by EGD. After the release by the Supreme Court of Canada of its 2004 decision in the EGD case, the plaintiffs in the electric utilities late payment class action indicated their intention to proceed with their litigation. To date, no formal steps have been taken to move the action forward. Any implications of the EGD decision in the Toronto Hydro class action cannot be determined at this time.

(c) Environmental matters:

As part of the Corporation's risk mitigation strategy, an environmental assessment is underway. At this time, it is not possible to determine the final outcomes of this assessment.

12. Commitments:

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default on their expected activity in the market. The IESO could draw on this security if the Corporation failed to make payment required by a default notice issued by the IESO. The Corporation has posted a letter of credit as security in the amount of $16,618 (2005 - $16,618).

The Corporation has also guaranteed the obligations of a subsidiary's financial energy supply contracts in the amount of nil (2005 - $3,000). The Corporation has a letter of guarantee from OESC in the amount of $1,600 (2005 - $1,600) in respect of the Corporation's requirement to post parental guarantees. The Corporation is liable for 57.7% of the parental guarantee to Ontario Power Generation Corporation with the minority interest shareholder liable for the remaining 42.3%.

13. Financial instruments:

The carrying values of cash and cash equivalents, accounts receivable, deposits and prudentials, accounts payable and accrued liabilities and advance payments approximate fair values because of the short maturity of these financial instruments.

The bonds, having a carrying value of $290,000 (2005 - $290,000), have a fair value of $310,854 (2005 - $316,329), based on year-end quoted market prices. Financial assets held by the Corporation expose it to credit risk. As at December 31, 2006 and 2005, there were no significant concentrations of credit risk with respect to any class of financial assets. The Corporation earns its revenue from a broad base of customers located principally in Mississauga. No single customer in either year would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

As part of the Asset Transfer Agreement executed to complete the sale of the retail customer contracts, the Corporation assigned its existing portfolio of energy supply contracts. The energy supply contracts were put in place as part of a strategy to manage price volatility for a portion of the electricity the retail customer contracts provided under these fixed pricing arrangements and not for speculative purposes. The contracts require the Corporation to exchange with counterparties the difference between fixed and variable amounts based on a notional quantity of electricity. Under provisions of the Asset Transfer Agreement, the purchaser is required to provide standby letters of credit (note 5) to guarantee any margin call related to the Corporation's portfolio of energy supply contracts. These letters of credit are necessary as the Corporation remains a guarantor to the original counterparties that it contracted with to provide electricity at a fixed price, notwithstanding assignment of these contracts to the purchaser of the retail customer contracts.

14. Related party transactions:

The Corporation's operations include the provision of electricity and services to its principal shareholder, the City of Mississauga. Electricity is billed to the City at the prices and terms established between the City and its electricity retailer. Streetlighting maintenance services are provided on a time and materials basis at an exchange amount, being that amount agreed to by the parties. A summary of amounts charged by the Corporation to the City of Mississauga is as follows:

	2006	2005
Electrical energy	$ 6,751	$ 7,572
Streetlighting maintenance	2,428	2,061
Streetlighting energy	3,371	4,013

The Corporation charged the City $1,495 (2005 - $1,918) for other construction services in 2006.

At December 31, 2006, accounts payable and accrued liabilities include $57 (2005 - $96) due to the City and accounts receivable include $2,412 (2005 - $2,647) due from the City.

The Corporation charged BPC $7 (2005 - nil) for an access agreement and nil (2005 - $159) for consulting services in 2006. These transactions were recorded at the exchange amount being the amount agreed to by the parties. At December 31, 2006, accounts receivable included $1 (2005 - $24) due from BPC.

Enerpower Corporation is an organization in which the Corporation has a 10% ownership interest. The Corporation was charged $7,563 (2005 - $6,385) by Enerpower Corporation during 2006 for the construction of distribution infrastructure. The Corporation received a dividend from Enerpower Corporation during 2006 of $53 (2005 - $66).

15. Energy purchases:

All electricity purchases for standard supply customers are subject to pricing determined by the IESO, a provincial government body.

Included in accounts payable and accrued liabilities as at December 31, 2006 is $49,974 (2005 - $64,832) owed in respect of electricity purchases through the IESO.

16. Interest and asset coverage ratios:

Interest coverage on long-term debt	1.89 times
Net tangible asset coverage on long-term debt	1.67 times

17. Segmented information:

The Corporation operates primarily in two operating segments, electricity distribution services and other operations. Other operations are primarily comprised of specialized design, construction and maintenance services for utilities and developers. The sale of water heater rental assets and associated customer rental contracts closed in January 2006 and the sale of fibre optic telecommunication assets and related customer contracts closed in May 2006 and both sales have been presented below as income (loss) from discontinued operations. Energy retail operations ceased with the sale of energy contracts effective May 1, 2003 and are also presented below as income (loss) from discontinued operations.

17. Segmented information (continued):

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies.

2006	Electricity distribution services	Other operations	Intersegment eliminations	Total
Revenue	$ 671,397	$ 9,696	$ (775)	$ 680,318
Operating expenses	594,726	10,188	(704)	604,210
Amortization	37,419	10	–	37,429
	632,145	10,198	(704)	641,639
	39,252	(502)	(71)	38,679
Interest revenue	2,764	400	–	3,164
Interest expense	(18,595)	–	–	(18,595)
Income (loss) before the undernoted	23,421	(102)	(71)	23,248
Recoveries (payments) in lieu of corporate income taxes	(10,119)	181	–	(9,938)
Income from discontinued operations, net of payments in lieu of corporate income taxes	–	3,844	72	3,916
Net income	$ 13,302	$ 3,923	$ 1	$ 17,226
Total assets	$ 585,375	$ 234,150	$ (203,858)	$ 615,667
Capital expenditures	$ 35,886	$ 6	$ –	$ 35,892
Cash provided by (used in) operations	14,202	(1,343)	–	12,859

17. Segmented information (continued):

2005	Electricity distribution services	Other operations	Intersegment eliminations	Total
Revenue	$ 782,362	$ 12,130	$ (4,501)	$ 789,991
Operating expenses	707,786	11,364	(3,931)	715,219
Amortization	37,279	5	–	37,284
	745,065	11,369	(3,931)	752,503
	37,297	761	(570)	37,488
Interest revenue	1,718	197	–	1,915
Interest expense	(17,677)	(14)	–	(17,691)
Income (loss) before the undernoted	21,338	944	(570)	21,712
Payments in lieu of corporate income taxes	(8,559)	(459)	–	(9,018)
Income from discontinued operations, net of payments in lieu of corporate income taxes	–	170	556	726
Net income (loss)	$ 12,779	$ 655	$ (14)	$ 13,420
Assets:				
From continued operations	$ 623,925	$ 209,356	$ (204,396)	$ 628,885
Held for sale	–	23,974	–	23,974
Total assets	$ 623,925	$ 233,330	$ (204,396)	$ 652,859
Capital expenditures	$ 30,224	$ 21	$ –	$ 30,245
Cash provided by (used in) operations	78,323	(1,031)	–	77,292

18. Comparative figures:

Certain 2005 figures have been reclassified to conform with the financial statement presentation adopted in 2006.

enersource Corporation

Management's Discussion and Analysis of Financial Condition and Results of Operations For the Year Ended December 31, 2006

($000 CAD)

The following discussion and analysis is prepared as of April 19, 2007 and should be read in conjunction with the consolidated financial statements and accompanying notes of Enersource Corporation ("Enersource") as at and for the year ended December 31, 2006.

GENERAL

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles considering regulatory requirements where applicable. The financial statements as presented include results for both the regulated and non-regulated business activities. The Enersource Corporation group of companies includes Enersource, Enersource Hydro Mississauga Inc. ("Enersource Hydro"), Enersource Services Inc., Enersource Telecom Inc. ("Telecom"), Enersource Hydro Mississauga Services Inc. ("EHM Services"), Enersource Technologies Inc. and First Source Energy Corporation ("First Source").

Enersource is a holding company established in response to the restructuring and deregulation of Ontario's electricity industry. Enersource's principal operating subsidiary, Enersource Hydro, is the regulated electricity distributor for the City of Mississauga. The *Energy Competition Act, 1998*, and its enabling regulations, distinguish and require the separation of regulated distribution businesses from non-regulated business activities. Enersource has organized other affiliated companies and related entities for the purpose of operating its non-distribution related businesses.

Telecom, a non-regulated subsidiary of Enersource was a data networks infrastructure enterprise which offered a range of services including high-speed data, voice and video communications links via fibre optic cable technology.

EHM Services is a non-regulated subsidiary of Enersource with a primary business focus on providing electrical infrastructure design, procurement, construction, commissioning, and operating and maintenance services to businesses and other utilities. EHM Services also provides a range of utility and industry services and products including streetlight asset construction and maintenance and electricity wholesale market settlement services. Golden Horseshoe, a joint venture between EHM Services and Oakville Hydro Energy Services Inc., had been formed to supply and install smart meters in multi-unit residential buildings in Ontario. EHM Services exited from the joint venture in December, 2006 by divesting its shares to Oakville Hydro Energy Services Inc. EHM Services did not record any economic benefits or losses from the joint venture or the share divestiture.

Enersource's strategy is concentrated on its core energy competencies in both regulated and non-regulated markets. To facilitate this strategy, certain assets within EHM Services and Telecom have been divested. The sale of over 12,000 electric water heater customer contracts, rental agreements and related assets from EHM Services to Union Energy Limited Partnership closed on January 23, 2006 ("water heater sale"). A separate sale of specific Telecom assets to Oakville Hydro Communications Inc. (Blink Communications) closed on May 24, 2006 ("Telecom sale"). Results from these operations for both 2006 and 2005 are disclosed as discontinued operations on the consolidated statement of income and the assets to be sold are disclosed as assets held for sale on the balance sheet.

First Source, a licensed retailer of electricity in the Province of Ontario, is owned 57.7% by Enersource and 42.3% by Veridian Corporation. First Source remains a dormant corporation and has been presented in the consolidated financial statements within discontinued operations.

RATE REGULATION

On November 25, 2003, Ontario Energy Minister Dwight Duncan introduced to the legislature Bill 4. This legislation allowed for the third and final market-based distribution rate increase to be implemented March 1, 2005 in order to achieve a full commercial return. This increase was conditional on LDCs reinvesting a prescribed amount of the incremental revenue from the rate increase into conservation and demand management initiatives.

On March 11, 2005, the Ontario Energy Board ("OEB") announced changes to electricity prices for residential, low-volume and designated customers to take effect April 1, 2005. Electricity prices increased effective April 1 from $0.047/kWh to $0.050/kWh for the first 750 kWh consumed in a month, and from $0.055/kWh to $0.058/kWh for consumption in excess of that amount. Commencing November 1, 2005, the price threshold would change twice a year. The new price thresholds set out in this announcement were 1,000 kWh per month during the November 1st through April 30th period and 750 kWh in the May 1st through October 31st period ("the 2005 pricing"). The new plan was designed to ensure that electricity pricing to low volume customers better reflects the true cost of power while also helping customers manage their electricity costs in a stable and predictable manner.

On April 12, 2006, the OEB announced further changes to electricity prices for regulated price plan customers to take effect May 1, 2006. Electricity prices increased effective May 1, 2006 from $0.050/kWh to $0.058/kWh for the first 600 kWh consumed in a month and from $0.058/kWh to $0.067/kWh for consumption in excess of that amount. The price threshold of 600 kWh covered the May 1st through October 31st period with a 1,000 kWh per month threshold during the November 1st through April 30th period ("the 2006 pricing"). The threshold for non-residential customers that are eligible for the regulated price plan remained unchanged at 750 kWh per month throughout the year.

On October 11, 2006, the OEB announced additional changes to electricity prices for regulated price plan customers to take effect November 1, 2006. Electricity prices would decrease effective November 1, 2006 from $0.058/kWh to $0.055/kWh for the first 1,000 kWh consumed in a month and from $0.067/kWh to $0.064/kWh for monthly consumption in excess of that amount. Electricity prices for the regulated price plan are expected to be adjusted every six months by the OEB as required.

On April 1, 2004, pending the final outcome of regulatory asset hearings and decisions, the recovery of LDC regulatory asset costs commenced on a provisional basis. On December 9, 2004, the OEB released its decision on the recovery of regulatory asset costs claimed by Enersource Hydro. Enersource Hydro received a rate order from the OEB granting it the right to recover $26,700 of regulatory asset costs through its distribution rates over the period April 1, 2004 through March 31, 2008.

In August 2005, Enersource Hydro submitted a rate application to the OEB for the rate period May 1, 2006 through April 30, 2007. This rate application allowed for the full re-basing of Enersource Hydro's electricity distribution rates to more accurately reflect Enersource Hydro's rate base and cost structure. On April 12, 2006, the OEB released its decision and order regarding Enersource Hydro's rate application. The decision supported growth of $23,400 or 5.2% in Enersource Hydro's rate base. This decision resulted in a distribution rate increase effective May 1, 2006 of approximately 2.3% on the total bill or an increase of approximately 11.4% on the distribution portion of the energy bill of an average residential customer consuming 1,000 kWh of electricity per month. This increase also included a new rate component for smart meters signaling the launch of the Provincial Government's smart meter program.

Enersource Hydro submitted a review and vary application to the OEB to provide further evidence to support amounts disallowed in the April 12, 2006 decision. On October 3, 2006, the OEB released its final decision on this subsequent application and fully approved additional expense recoveries of approximately $1,152 annually and the disposition of retail settlement variance liabilities of approximately $2,714 over a two year period. The rate revisions resulting from this decision were implemented on November 1, 2006.

RESULTS OF OPERATIONS

Summary:

Consolidated net income before discontinued operations for the three months ended December 31, 2006 was $2,240 as compared to net income of $1,358 for the same period of 2005. The $882 increase in net income was primarily due to the effect of Enersource Hydro's distribution rate increase on May 1, 2006 combined with a contractual holdback of $1,784 received in the fourth quarter of 2006 pertaining to the Telecom sale. This impact was partially offset by other post closing sale adjustments and higher amounts due in lieu of corporate income taxes.

Consolidated net income before discontinued operations for the twelve months ended December 31, 2006 was $13,310 as compared to $12,694 for the same period of 2005. The $616 increase in net income was primarily due to the combined effect of Enersource Hydro's distribution rate increase on May 1, 2006 as well as a gain resulting from the sale of water heater assets. These impacts were partially offset by higher operations, maintenance and administration costs driven by a higher bad debt provision, reduced margins from services revenue, and a loss of $1,958 resulting from the Telecom sale.

Enersource declared and paid a dividend of $8,900 to its shareholders in the fourth quarter of 2006. This dividend was funded through a regular inter-corporate dividend of $7,667 and an additional special dividend of $1,233 from Enersource Hydro.

Enersource Hydro's regulatory assets as at December 31, 2006 were $12,179, of which $8,645 represented the outstanding balance of the regulatory hearing award. The remaining $3,534 represents other regulatory assets, primarily deferred pension and OEB assessed costs. The OEB has approved recovery of $1,258 for the 2004 portion of these deferred pension and OEB assessed costs commencing May 1, 2006, per its April 12, 2006 rate decision.

The consolidated cash position of Enersource at December 31, 2006 was $56,871 representing a decline of $3,842 on the year due primarily to the payment of Ontario Price Credit Rebates of $25,934 in early 2006. This rebate program was announced by the Ontario Government on October 20, 2005. Another factor contributing to the negative cash flow was increased capital investments of $5,647 in 2006 as compared to 2005. These cash outflows were largely offset by cash receipts of $24,704 received from the water heater sale and Telecom sale.

Revenues:

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Electricity Pass Through	127,303	167,846	557,271	672,412
Distribution Revenue	25,898	24,017	104,120	95,982
Recovery of Regulatory Assets	1,328	1,644	7,144	7,513
Energy Revenues	154,529	193,507	668,535	775,907

Energy revenues consist mainly of electricity passed through at cost to standard supply customers. All energy revenues are generated from regulated operations. For the fourth quarter ended December 31, 2006, electricity pass through revenue was $127,303 as compared to $167,846 for the fourth quarter of 2005, representing a reduction of $40,543 or 24.1%. This reduction was due to lower spot market prices for the 2006 period as well as a decline in consumption by Enersource Hydro's large users. The full effect of the 2006 pricing and consumption decline was partially offset by higher regulated commodity pricing in 2006 over 2005 for a substantial segment of the customer base. The electricity price increases which took effect May 1, 2006 were subsequently reduced effective November 1, 2006 for residential, small commercial, and other designated customers.

Energy revenue for the twelve-month period ended December 31, 2006 was $557,271 and was $115,141 lower than 2005 due to a 5% decline in consumption and lower spot market pricing in 2006. This decrease was offset in part by regulated commodity price increases for a substantial segment of the customer base for the period May 1, 2006 through October 31, 2006.

Distribution related revenue was $25,898 for the fourth quarter of 2006 compared to $24,017 for 2005, for an increase of $1,881. This increase was due to higher distribution rates effective May 1, 2006. Electricity consumption was lower in the quarter when compared to 2005 due to a decline in consumption for the large user customer base combined with the growing impact of conservation. Revenue related to the recovery of regulatory assets was $1,328 for the fourth quarter of 2006.

For the twelve-month period ended December 31, 2006, distribution related revenue was $104,120 compared to $95,982 for 2005 due to an increase in electricity distribution rates effective May 1, 2006. This rate increase generated $9,156 of additional revenue over the comparable 2005 period and was partially offset by a decrease of $1,018 due to a decline of 5% in electricity consumption. This decline in consumption resulted from a reduction of 154 cooling degree days (29%), during the summer months as well as a reduction of 419 heating degree days (11%) during the winter months in the period relative to 2005. Consumption was also negatively impacted as a result of ongoing conservation programs. Revenue related to the recovery of regulatory assets was $7,144 for the twelve-months ended December 31, 2006 as compared to $7,513 for the same period in 2005.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Services Revenue	1,559	2,135	8,829	11,814

Services revenue from non-regulated operations was generated from streetlighting services and engineering design and construction services. Water heater rentals and telecommunication service revenues have been reclassified as discontinued operations in the consolidated statement of income for both 2006 and 2005. A decrease of $576 in the 2006 fourth quarter services revenue from 2005 was the result of lower engineering design and construction activity and associated contract revenue.

A decrease of $2,985 in services revenue for the twelve-month period ended December 31, 2006 from 2005 was the result of lower engineering design and construction activity and associated contract revenue.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Distribution Operations	(3)	(33)	(3)	(190)
Other Operations	1,112	(1)	723	(1)
Gain(Loss) on Disposal of Capital Assets	1,109	(34)	720	(191)

Enersource Hydro recorded a loss on the disposal of capital assets of $3 for the fourth quarter ended December 31, 2006 as compared to a loss of $33 in the fourth quarter of 2005. Gains or losses are incurred on disposal of capital assets in the ordinary course of business in the regulated operations. A gain of $1,112 was recorded on disposal of capital assets in the non-regulated operations for the three-months ended December 31, 2006 as compared to a loss of $1 for the same 2005 period. This gain was primarily due to finalization of contractual holdbacks of $1,784 pertaining to the Telecom sale combined with other post-closing adjustments on this sale and the water heater sale.

Enersource Hydro incurred a loss on the disposal of capital assets of $3 for the twelve-months ended December 31, 2006 as compared to a loss of $190 in the same period of 2005. Gains or losses are incurred on disposal of capital assets in the ordinary course of business in the regulated operations. The gain on disposal of capital assets in non-regulated operations was $723 for 2006 as compared to a loss of $1 for 2005 due to a recorded gain of $2,592 from the water heater sale which was partially offset by a loss of $1,958 resulting from the Telecom sale.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Distribution Operations	563	494	2,179	2,368
Other Operations	-	66	55	93
Other Revenues	563	560	2,234	2,461

Other revenues generally consist of late payment charges, set-up charges, and pole rental fees within Enersource's utility operations. Other revenues generated by Enersource Hydro for the fourth quarter ended December 31, 2006 rose by $69 over the fourth quarter of 2005 due to higher proceeds from the sale of scrap and an increase in late payment charges.

Other revenues generated by Enersource Hydro for the twelve-month period ended December 31, 2006 declined by $189 primarily due to the non-recurring sale of distribution infrastructure design standards to other utilities in 2005.

Operating Expenses:

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Energy Purchases	127,303	167,846	557,271	672,412

Energy purchase expense, which is entirely attributed to regulated operations and is passed through to customers at cost, declined by $40,543 or 24.1% for the fourth quarter ended December 31, 2006 as compared to the corresponding quarter of 2005. This decrease was due to lower spot market prices and lower electricity consumption and was partially offset by higher regulated commodity pricing in 2006 over 2005 for a substantial segment of the customer base.

Energy purchase expense declined by $115,141 or 17.1% in the twelve-month period ended December 31, 2006 as compared to the same period of 2005 and was due to the aforementioned reasons.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Distribution Operations	10,947	10,523	37,303	32,416
Other Operations	761	678	3,075	1,704
Operations, Maintenance and Administration	11,708	11,201	40,378	34,120

Consolidated operations, maintenance and administration costs, or the overhead costs incurred to manage the operations of the regulated and non-regulated companies, increased by $507 or 4.5% for the quarter ended December 31, 2006 over the corresponding quarter in 2005. Enersource Hydro costs increased by $424 due to higher pension costs of $435 and higher OEB fixed costs assessed of $168, as both of these costs were deferred in 2005 for future recovery. Overhead costs of the non-regulated operations increased by $83 primarily due to lower cost allocations to construction and design projects in 2006 as compared to the corresponding period for 2005.

Consolidated operations, maintenance and administration costs increased by $6,258 or 18.3% for the year ending December 31, 2006 over the corresponding 2005 period. Enersource Hydro costs rose by $4,887 or 15.1% partially due to an increase of $1,338 in the bad debt provision related to customer backbillings. Other significant factors contributing to the increase were higher pension costs of $917 and OEB fixed costs assessed of $509, as both of these costs were deferred in 2005 for future recovery. Effective May 1, 2006, EHM, through an OEB decision, commenced recovery of the 2004 deferred pension and OEB amounts and the current year costs incurred since May 1, 2006. In addition, employee future benefits costs increased by $308 and conservation and demand management expenditures by $256. The remaining cost variance is primarily due to general economic increases in material and overhead expenses. Overhead costs pertaining to non-regulated operations increased by $1,371 in 2006 over 2005 primarily due to lower cost allocations to construction and design projects in 2006.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Cost of Services	1,189	1,584	6,561	8,687

The cost of services in non-regulated operations of $1,189 was $395 lower for the quarter ending December 31, 2006 than for the corresponding quarter of 2005 as a result of a decline in engineering design and construction contract activity. Margins on services revenues for the quarter ended December 31, 2006 were lower than the margins earned for the corresponding period of 2005. Notwithstanding this decline, the variance on margins for this business area is not considered significant on a year-to-year basis as fluctuations regularly occur in the mix of work and the margins which can be obtained.

The cost of services in non-regulated operations declined by $2,126 for the twelve-months ended December 31, 2006 from 2005 due a reduction in engineering design and construction contract activity. Margins on services revenues for 2006 were lower than the margins earned in 2005. Notwithstanding this decline, the variance on margins for this business area is not considered significant on a year-to-year basis as fluctuations regularly occur in the mix of work and the margins which can be obtained.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Distribution Operations	7,967	7,737	30,275	29,766
Other Operations	4	2	10	5
Amortization of Capital Assets	7,971	7,739	30,285	29,771

Amortization of capital assets increased by $230 for the quarter ended December 31, 2006 over the corresponding period of 2005 in Enersource Hydro primarily due to the continuing investment in electricity distribution infrastructure.

Amortization of capital assets increased by $509 for the twelve-months ended December 31, 2006 over the corresponding period of 2005 in Enersource Hydro primarily due to the continuing investment in electricity distribution infrastructure. Enersource Hydro's investment in capital assets for 2006 was $35,886.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Amortization of Regulatory Assets	1,328	1,644	7,144	7,513

Amortization of regulatory assets for the quarter ended December 31, 2006 was $1,328. The passing of Bill 4, in part, directed LDCs to commence recovery of the cost of regulatory assets through electricity distribution rates over a four-year period effective April 1, 2004. Regulatory asset deferred costs were amortized at a rate corresponding to the amount recovered through electricity distribution revenues.

Amortization of regulatory assets declined by $369 for the twelve-months ended December 31, 2006 from 2005 primarily due to the OEB's decision to dispose of retail settlement variances as of December 31, 2004.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Operating Income	8,261	6,154	38,679	37,488

Consolidated operating income increased by $2,107 in the fourth quarter of 2006 over 2005. This increase was due to a rise of $1,881 in Enersource Hydro distribution revenue combined with the release of a contractual holdback of $1,784 from the Telecom sale, the combined effect of which was partially offset by an increase of $507 in operations, maintenance and administration expense and an increase of $232 in amortization of capital assets.

Consolidated operating income increased by $1,191 for the twelve-months ended December 31, 2006 over 2005. The growth in operating income was due to Enersource Hydro distribution revenue growth of $8,138 combined with an incremental gain of $911 on the disposal of capital assets, which was partially offset by an increase of $6,258 in operations, maintenance and administration expense, a reduction of $859 in EHM Services margins and an increase of $514 in amortization of capital assets.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Distribution Operations	764	481	2,764	1,718
Other Operations	108	61	400	197
Interest Income	872	542	3,164	1,915

Interest income from Enersource Hydro for the quarter ended December 31, 2006 rose by $283 over the corresponding period of 2005 as average interest rates surpassed the corresponding 2005 rates. Interest income from other operations increased by $47 for the quarter ended December 31, 2006 over 2005 due to a rise in average cash balances from the water heater and Telecom sales combined with higher average interest rates.

Interest income from Enersource Hydro for 2006 rose by $1,046 over 2005. The average cash position of Enersource Hydro during 2006 was higher than that of 2005 and average interest rates for 2006 surpassed 2005. Interest income from other operations increased by $203 for 2006 over 2005 due to the aforementioned factors.

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Distribution Operations	(4,926)	(4,275)	(18,595)	(17,678)
Other Operations	-	-	-	(13)
Interest Expense	(4,926)	(4,275)	(18,595)	(17,691)

For the quarter ended December 31, 2006, $4,598 of Enersource Hydro's interest expense was attributable to bonds with additional accrued interest of $200 on customer deposits.

For the twelve-months ended December 31, 2006, $18,241 of Enersource Hydro's interest expense was attributable to bonds with additional accrued interest of $697 on customer deposits. Capitalized interest for the year was $819 as compared to $1,459 for 2005.

Consolidated Cash Flows

	4th Qtr 2006	4th Qtr 2005	YTD Dec 2006	YTD Dec 2005
Increase (Decrease) in Cash And Cash equivalents	(5,282)	31,240	(3,842)	34,205

During the three months ended December 31, 2006, net cash outflow was $5,282 as compared to net inflow of $31,240 for the corresponding period in 2005. The net cash inflow in the 2005 quarter was largely due to the receipt of $25,934 for the Ontario Price Credit rebate program. Net cash outflow for 2006 include incremental capital expenditures of $2,122 and changes in non-cash working capital.

During the twelve months ended December 31, 2006, net cash outflow was $3,842 as compared to a net inflow of $34,205 for the corresponding period in 2005. Net cash flow declined largely due to the disbursement of $25,934 in Ontario Price Credit rebates to customers in early 2006, which were originally received in December 2005. Capital asset investment in 2006 increased by $5,647 as compared to 2005 and non-cash working capital changes driven by lower year end balances of accounts payable and accrued liabilities and higher unbilled receivables also contributed to the negative variance. These cash outflows were offset in part by $25,136 in cash proceeds generated from the sale of water heating and Telecom assets.

Capital Expenditures

The Corporation's capital expenditures were primarily attributable to investment in distribution system infrastructure in response to rising electricity demand and reliability requirements within Mississauga. Capital asset investment strategies are developed and reviewed continuously to maintain pace with the growing demand for electricity and to ensure that the operating performance of Enersource's distribution system, the condition of its assets and its customer service levels are all maintained to the highest industry standards. .

Total capital asset additions for the twelve months ended December 31, 2006 were $35,892 as compared to $30,245 for the corresponding period in 2005. During 2006, distribution system capacity-related investment was $8,138, with system upgrades of $12,001 and system expansion-related investment of $5,587. Non-distribution system investment was $10,166 and was inclusive of information technology, fleet vehicles, smart meters and conservation and demand management capital initiatives.

Liquidity and Capital Resources

The Corporation's primary sources of liquidity and capital resources are funds from operating activities as well as an established banking line of credit, if required. These resources are primarily used for capital expenditures to maintain the electricity distribution system, and for servicing interest expense on debt.

Interest, Asset Coverage, and Working Capital Ratios	Dec, 2006	Dec, 2005
Interest coverage on long-term debt	1.89 times	1.69 times
Net tangible asset coverage on long-term debt	1.67 times	1.53 times
Working capital ratio	1.97	1.39

The interest coverage on long-term debt ratio of 1.89 times for 2006 has increased from 1.69 times for 2005 primarily due to growth of $3,806 in net income.

The net tangible asset coverage on long-term debt ratio was 1.67 as at December 31, 2006 and was higher than the 1.53 as of December 31, 2005 primarily due to a reduction in current liabilities.

The Working Capital Ratio was 1.97 as at December 31, 2006 compared to a ratio of 1.39 as at December 31, 2005 due to a reduction in current liabilities, predominately accounts payable and accrued liabilities ($81,094 as at December 31, 2006 as compared to $118,640 as at December 31, 2005).

Enersource's bank line of credit in the amount of $50,000 was not utilized during 2006 and with stable cash flows and a positive future outlook there is little likelihood of utilization of this facility in 2007.

Contractual Obligations

The following table presents a summary of debt and other major contractual obligations as at December 31, 2006:

December 31, 2006 ($000's)	**Total**	**2007**	**2008/2009**	**2010/2011**	**After 2011**
Due By Year:					
Long-term debt	290,000	-	-	290,000	-
Capital purchase obligations	6,844	6,844	-	-	-
Operating leases	2	2	-	-	-
Total Contractual obligations	296,846	6,846	-	290,000	-

Related Party Transactions

The Corporation's operations include the provision of electricity and services to its principal shareholder, the City of Mississauga in the normal course of business. Electricity is billed to the City at the prices and terms established between the City and its electricity retailer. Streetlighting maintenance services are provided on a time and materials basis at an exchange amount, being that amount agreed to by the parties. A summary of amounts charged by the Corporation to the City of Mississauga for the year ended December 31, 2006 is as follows:

	2006	2005
Electrical Energy	$6,951	$7,572
Streetlighting Maintenance	2,428	2,061
Streetlighting Energy	3,371	4,013

The Corporation charged the City $1,495 (2005 - $1,918) for other construction services in 2006. These transactions were recorded at the exchange amount, being the amount agreed to by the parties.

At December 31, 2006, accounts payable and accrued liabilities due to the City were $57 (2005 - $96). Accounts receivable due from the City was $2,412 (2005 - $2,647) at December 31, 2006.

The Corporation charged Borealis $7 (2005 - nil) for an access agreement in 2006 and nil (2005 - $159) for consulting services in 2006. These transactions were recorded at the exchange amount, being the amount agreed to by the parties.

At December 31, 2006, accounts receivable included $1 (2005 - $24) due from Borealis.

The Corporation was charged $7,563 in 2006 (2005 - $6,385) by Enerpower Corporation, an organization for which the Corporation has a 10% ownership interest, during 2006 for the construction of distribution infrastructure. The Corporation received a dividend from Enerpower Corporation during 2006 of $53 (2005 - $66).

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters beginning January 1, 2005 and ending December 31, 2006. This information has been derived from Enersource's unaudited interim Consolidated Financial Statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance. The consumption of electricity generally follows the number of cooling degree days during the summer months and heating degree days during the winter months, and therefore energy related revenue, all other things being equal, tend to be higher during the first and third quarters.

	2006				2005			
	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar
Total Revenue	$157,760	$187,628	$157,305	$177,625	$196,168	$237,160	$184,675	$171,988
Total Expense	155,520	181,211	157,828	172,449	194,810	232,057	180,450	169,980
Net Income from Operations	2,240	6,417	(523)	5,176	1,358	5,103	4,225	2,008
Discontinued Operations	196	(87)	2,888	919	635	320	(177)	(52)
Net Income	$2,436	$6,330	$2,365	$6,095	$1,993	$5,423	$4,048	$1,956
Dividends	$8,900				$8,900			

SIGNIFICANT ACCOUNTING PRONOUNCEMENTS

Asset Retirement Obligations

The Canadian Institute of Chartered Accountants ("CICA") issued Handbook Section 3110, Asset Retirement Obligations wherein a liability is to be recognized where a legal commitment has been incurred to remove in-service fixed assets at some future date. Enersource Hydro distribution assets are load-servicing assets of a network-type configuration. The demand on these assets is permanent and continuity of service is critical. Therefore, the Corporation upon adoption of this accounting standard has recognized no obligations. Should any aspect of our distribution operations change to limit or eliminate the perpetual demand on certain in-service assets, the Corporation will recognize an obligation and offsetting capital asset when the value and timing of the obligation can be reasonably estimated.

Employee Future Benefits

The total net employee future benefit cost for the fourth quarter ended December 31, 2006 was $233 as compared to $23 for the fourth quarter ended December 31, 2005. The total net employee future benefit cost for the twelve-months ended December 31, 2006 was $514 as compared to $91 for the twelve-months ended December 31, 2005.

The major driver for the future benefit cost variance is a newly introduced retiree bridge benefits program which came into effect on June 1, 2006. Enersource employees who are at least 55 years of age with 10 or more years of service qualify for the plan with a specified cost sharing formula for participation from the time of early retirement to age 65. The net employee future benefit cost for this program for the fourth quarter ended December 31, 2006 was $177 as compared to nil for the fourth quarter ended December 31, 2005. The net employee future benefit cost for this program for the twelve-months ended December 31, 2006 was $383 as compared to nil for the twelve-months ended December 31, 2005.

Please refer to the consolidated financial statements note 8 for more detailed information regarding the employee future benefit plans.

Accounting Guideline 19 – Disclosures by Entities Subject to Rate Regulation

The CICA issued Accounting Guideline 19 ("AcG-19") in October 2005 that modified existing accounting standards as a result of the unique characteristics of rate-regulated operations. Enersource Hydro's operations are regulated by the OEB.

Under AcG-19, certain disclosures are required to identify the impact of regulatory accounting procedures that differ from GAAP on the financial statements of rate-regulated entities. Enersource's financial statements include accounting procedures that are required as a result of the OEB's regulatory oversight over Enersource Hydro's operations. In the absence of those regulatory accounting procedures that differ from GAAP on the 2006 Consolidated Statement of Income, net income would decline by $3,006.

RISK MANAGEMENT

Enersource utilizes a risk management program to minimize business risks while maximizing returns to shareholders. A corporate risk assessment is undertaken annually under the guidance of Enersource's Audit Committee. This annual assessment identifies all operating risks for the organization and categorizes these risks according to significance and probability of occurrence. Risks that are deemed significant with a moderate to high probability of occurrence are analyzed for the purpose of developing mitigating strategies and implementing operational controls.

Regulatory Risk

Enersource Hydro's operations are regulated by the OEB. The OEB exercises statutory authority over matters such as operational performance, rate setting, and financial returns.

On May 31, 2004, the Ontario Government, through the OEB, directed all Electricity Distribution Utilities to conduct a Conservation and Demand Management ("CDM") program to be funded from their third and final market-based rate increase. These programs are specifically designed to reduce electricity consumption throughout the province by way of technologies, customer awareness and incentives. For Enersource Hydro, this commitment represents an investment of $8,200 over the period from April, 2005 through September, 2007.

The Ontario Government has proposed a revenue adjustment mechanism to compensate utilities for lost revenues as a result of conservation programs. To date however, and until the rate application process for recovery of lost revenues is formalized, distribution revenues lost as a result of conservation programs remain at risk.

On July 16, 2004, the Ontario Government announced that all electricity consumers in Ontario will have a smart meter no later than December 31, 2010. Smart meters will provide all customers with time of use data that will allow them to monitor their electricity usage in hourly intervals. The implementation of interval pricing will then allow customers to manage their electricity consumption based on time of use and preferred price. The first phase of this program requires that 800,000 Smart Meters be installed throughout the province by December 31, 2007.

The Ontario Ministry of Energy has requested that the OEB prepare an implementation plan. The OEB's final report to the Ministry of Energy regarding the implementation plan identifies local distribution companies as the source of funding for the supply and installation of the smart meters. Enersource Hydro is committed to executing the Ministry of Energy's smart meter initiative to the full extent of OEB approvals. Notwithstanding the recent announcements regarding the smart meter program, the extent of the OEB's approval of Enersource Hydro's smart meter applications will dictate the timing and extent of implementation and as such, the impact of timing on Enersource Hydro's cash flows is uncertain.

Electricity Supply Risk

At peak consumption periods the Independent Electricity System Operator ("IESO") may publish public appeals for reduced energy consumption with warnings of brownouts or blackouts if consumption was not reduced. In the event of a brownout or blackout in Mississauga due to electricity consumption levels exceeding available supply from the IESO, Enersource Hydro's distribution revenue would be adversely affected and as such, represents financial risk to the Company.

Environmental Risk

Enersource is subject to numerous environmental regulations. As part of Enersource's risk mitigation strategy an environmental assessment is currently underway. At this time, it is not possible to determine the final outcomes of this assessment.

OUTLOOK

Rationalization of Ontario's electricity distribution sector continued to advance with the re-basing of distribution rates for 2006, the first re-basing of rates since 1999. The re-basing of Enersource Hydro's distribution rates has provided for further stabilization of income streams and cash flows and will position the company and the industry at large for transition to a performance based regulatory regime.

Enersource Hydro is part of a coalition of six large electricity distributors within the province launching a significant smart meter initiative to fulfill the provincial government's plan for installation of 800,000 smart meters throughout the province by 2007. These meters will capture time of use consumption data to be used by customers to manage their electricity usage and cost. This program, along with conservation and demand management initiatives currently under way, are designed to form the cornerstones of an energy awareness and conservation culture in Ontario.

On April 22, 2004, the Supreme Court of Canada ruled on the case of Gordon Garland v. Enbridge Gas Distribution Inc. The court concluded that the late penalties, which the natural gas utility had charged customers from 1994 to 2002, exceeded legal limits and amounted to criminal misconduct. A settlement was reached between the parties on July 20, 2006 which proposes that Enbridge will pay out approximately $21,200 including a $9,000 donation to the Winter Warmth Fund prior to the end of January 2007, approximately $10,200 for the plaintiff's legal fees and expenses, and a payment of approximately $2,000 to the Class Proceedings Fund, operated by the Law Foundation of Ontario. The Supreme Court on review of the proposal directed that certain changes be made to the agreement. The parties are now in the process of reviewing those changes. The Electricity Distributors Association is reviewing the potential implications of the decision on the electricity distribution sector. It is too early to tell if the Enbridge decision impacts the electricity distribution utilities and, as such, any potential exposure for Enersource Hydro is indeterminable at this time.

Enersource has implemented a strategy to refocus its business activities on its core competencies. As a result of this strategic re-positioning, the corporation sold its water heater assets and related customer rental agreements on January 23, 2006 and sold its Telecom fibre optic infrastructure assets and related customer contracts on May 24, 2006.

EHM Services has recently signed an MOA with Ontario Power Generation and BPC Energy Corp. to explore the opportunities for a gas fuelled generation facility at the former Lakeview Generating Station site.

EHM Services is the home of Enersource Technologies, a successful business line providing electrical infrastructure design, procurement, construction, commissioning and operations services to utilities and the development community. Of note for this business was the successful expansion and re-development of the electrical infrastructure of Pearson International Airport for the Greater Toronto Airports Authority. EHM Services also operates profit generating business lines such as streetlighting construction and maintenance services.

Enersource will continue to focus on operational excellence, customer care and shareholder value in its regulated and non-regulated businesses with a continued emphasis on growth and financial stability.

Forward looking information

Readers should be aware that historical results are not necessarily indicative of future performance. As well, this MD&A contains certain forward-looking statements that reflect Enersource's current expectations, as well as projections about its future operations. These future expectations and projections are subject to business risks, uncertainties and other factors including, but not limited to, regulatory risk and electricity supply risk. Readers are cautioned that actual performance may differ materially from estimated performance based upon the forward-looking statements and that these forward-looking statements speak only as of the date of this MD&A. Enersource has no intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

ONTARIO SECURITIES COMMISSION REQUIRED DISCLOSURES

Certification of Disclosure in Issuers' Annual Filings

Enersource Corporation is a reporting issuer and, as such, must comply with Multilateral Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* (the "Instrument"). Enersource is further sub-classified as a venture issuer and our certifying officers have reviewed and certified the consolidated financial statements for the year ended December 31, 2006. Our certifying officers have also certified that internal controls over the preparation of financial statements have been designed and disclosure controls and procedures as at December 31, 2006 have been designed, implemented and evaluated. As a result of the evaluation of disclosure controls and procedures, management has concluded that these disclosure controls and procedures provide reasonable assurance that all material information necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

The Instrument also requires that the certifying officers disclose any change in internal control over financial reporting that occurred during Enersource's most recent interim period that has materially affected, or is likely to materially affect, Enersource's internal control over financial reporting.

During the fourth quarter of 2006, Enersource enhanced its controls for the initiation, approval and release of wire transfer payments. Prior to this enhancement, wire transfer payment approvals were manually obtained prior to the release of the wire payments. The new control process involves a password protected electronic initiation, approval and release protocol for wire transfer payments with sequential and segregated initiation, approval and release path.

Corporate Governance Disclosure

Enersource Corporation is a reporting issuer and, as such, must comply with National Instrument 58-101 – *Disclosure of Corporate Governance Practices*. Enersource is further sub-classified as a venture issuer and provides the following disclosures in accordance with the instrument:

The Enersource Corporation Board of Directors (the "Board") is comprised of Dr. Alex Taylor (Chair), Mayor Hazel McCallion, Michael J. Nobrega, Robert M. Watters, Nando Iannicca, Janice Baker, Ronald E. Starr, Gerald E. Beasley, Christopher R. Chorlton and Norman B. Loberg. All of the members of the Board are independent within the meaning defined by section 1.4 of Multilateral Instrument 52-110.

The Board Chair is Dr. Alex Taylor who is an independent director. The principal role of the Chairman is, as the presiding member of the Board and accountable to the Board, to ensure that the relationships between the Board and management, the shareholders, other stakeholders and the individuals on the Board are managed effectively and efficiently and further the best interests of the Corporation.

The independent directors hold regular meetings. These meetings are attended by management and there are no non-independent directors. A portion of every Board of Directors meeting is held without the attendance of management.

The following members of Enersource's Board of Directors serve on a Board of Directors of other reporting issuers:

Director	**Reporting Issuer**
Michael J. Nobrega	Primaris Retail Real Estate Investment Trust
Robert M. Watters	Scotia Gas Networks PLC
	Associated British Ports Holdings PLC
Norman B. Loberg	Greater Toronto Airports Authority

Enersource Corporation provides new directors with detailed orientation information materials explaining the history of the company and the industry within which it operates, financial and budget information and the company's strategic direction. Management strives to ensure that directors are kept fully informed of new relevant information.

The Corporation promotes integrity as one of the foundations of its vision and values. In order to further encourage and promote a culture of ethical business conduct, the board has adopted a written code of ethics for the directors, officers and employees. The code has been distributed to all directors, officers and employees. Additional copies of the code are available internally on the Corporation's Intranet and from the Human Resources Department and a copy has been externally filed on SEDAR.

Compliance by directors is monitored by the Chair through his observations of compliance and through annual interviews between himself and each director. Compliance by officers and employees is assessed by a management ethics committee and violations are reported to the Human Resources and Corporate Governance Committee.

Formal nomination and appointment of a director to the Enersource Board of Directors is made by Enersource's shareholders, although, under certain circumstances, an appointment may be made by the board of directors.

On February 14, 2007, the Council of the City of Mississauga passed a resolution that the Enersource Board of Directors be composed of the Mayor, three Councillors and four citizens to be appointed by Council and two members from Borealis (to be appointed by Borealis).

Periodically, compensation of the board members is reviewed by the Human Resources and Corporate Governance Committee and, as appropriate, it makes recommendations to the board of directors for amendments. All amendments to director compensation must be approved by Enersource's shareholders.

Four Board Committees report to the Board:

Audit Committee

The Audit Committee is accountable to the Board for providing oversight of the reliability and integrity of the Corporation's accounting principles and practices, business planning, financial reporting, system of internal control, management information and risk management processes.

The internal auditor and external auditor are invited to attend all meetings of the Audit Committee and receive all agendas and associated material. As part of all meetings, the Audit Committee meets with the internal and external auditors independent of management.

Human Resources and Corporate Governance Committee

The Human Resources and Corporate Governance Committee is accountable to the Board for oversight of the Corporation's human resources and compensation policies and practices. The Committee is also responsible for ensuring that effective corporate governance processes are in place and for making recommendations to the Board with respect to the development, implementation and modification of those processes.

Development Committee

The Development Committee is accountable to the Board for providing oversight of the Corporation's business development plans and activities and for making recommendations to the Board with respect to their potential applicability, risks and rewards.

Health, Safety and Environment Committee

The Health, Safety and Environment Committee is accountable to the Board for oversight of the management of the Corporation's health, safety and environmental risks and making recommendations to the Board with respect to development, implementation, communication, and related management processes.

Mandates are in place for the Board, individual Directors, the Chairman, the President and Chief Executive Officer, and the four committees of the Board. In late 2006, the Board carried out a review of its effectiveness through individual meetings with the Chairman aided by self assessment questionnaires. Each Board Committee also reviewed its effectiveness.

Audit Committee Responsibilities and Composition

Enersource Corporation is a reporting issuer and, as such, must comply with Multilateral Instrument 52-110 – *Audit Committees*. Enersource is further sub-classified as a venture issuer and provides the following disclosures in accordance with the instrument:

The mandate of the Audit Committee is as follows:

1. Give advice and recommendations to the Board on financial and audit matters.
2. Review the risk management and insurance programs in place to be satisfied that they take into account the opportunities and risks of the business and evaluate their appropriateness in terms of identifying, monitoring and mitigating significant business risks.
3. Assure itself as to the integrity of internal control and management information systems.
4. Review the annual audited financial statements and assure itself that they are fairly presented in all material aspects in accordance with generally accepted accounting principles and that the accounting policies are appropriate before submission to the Board.
5. Review, prior to their public disclosure, public financial and disclosure documents and other reports required to be filed with security regulatory agencies and assure itself that disclosure is accurate, complete and fairly presents the financial position and the risks of the Corporation.
6. Review the overall scope and adequacy of external and internal audit plans, and be satisfied as to the independence of the auditors.
7. Review reports issued by internal and external auditors and management's response and action plans taken to remedy any identified weaknesses.
8. Pre-approve all audit-related and non-audit services to be provided by the external auditor in accordance with the approved policy.
9. Review and approve the Corporation's hiring policies regarding partners, employees, and former partners and employees of the present and former external auditor.
10. The external auditors report directly to the Audit Committee. Review performance of the external auditors and annually recommend the appointment of the external auditors, including auditors' fees.
11. Review any significant legal or regulatory issues.
12. Review policies and procedures with respect to the Chairman of the Board, the President and Chief Executive Officer, and Director's expenses, and periodically review a summary of major expenses incurred by the Chairman and the President and Chief Executive Officer.
13. At least once each quarter, the Audit Committee will meet with both the Corporation's internal and external auditors, in the absence of any management representatives.
14. Engage independent counsel and other advisors as necessary and set the associated compensation.
15. Review annually the Audit Committee mandate and the Committee's effectiveness in carrying out the mandate.

The members of Enersource's Audit Committee are Gerald E. Beasley (Chair), Robert M. Watters, Nando Iannicca and Christopher R. Chorlton. All members are independent and financially literate as defined under applicable Canadian securities legislation.

Mr. Beasley holds an MBA from the University of Western Ontario with a specialty in Finance. Mr. Beasley's business experience includes thirty-one years with the Canadian Imperial Bank of Commerce concentrating in credit risk management, both domestic and international. Integral to this function is a broad and deep understanding of corporate financial statements. His last position with CIBC was Senior Executive Vice President, Risk Management, which he held for eight years. In addition to his Board of Director duties at Enersource, Mr. Beasley also currently serves on the Board and Audit Committee of First Canadian Title Insurance Co. Ltd. (not a reporting issuer). In the past, Mr. Beasley has served on the

Board of Directors of Allstream Corp., Newcourt Credit Corporation, CIBC Insurance, Edulinx Corporation and Trillium Health Centre Foundation among others.

Mr. Watters is a member of the Canadian Institute of Chartered Accountants. Mr. Watters currently serves as Senior Vice President at Borealis Infrastructure, a wholly-owned subsidiary of OMERS, where he is responsible for the development of energy, transportation and related infrastructure investment opportunities. He has held a number of senior positions as Chief Executive Officer, Chief Operating Officer and Chief Financial Officer in transportation, leasing, advertising and communications sectors prior to joining Borealis. In addition to serving on the Enersource Board of Directors, Mr. Watters is a Director on a number of other corporate Boards including Scotia Gas Networks PLC, Associated British Ports Holdings PLC, Express Pipeline Ltd., Ainsworth Inc. and is a member of the Board of Management for the Ontario Centre of Excellence in Energy.

Mr. Iannicca holds university degrees in journalism from Ryerson University, political science from the University of Guelph, and a minor degree in economics from Ryerson University and the University of Guelph. He has completed the Canadian Securities Course and obtained a Registered Representative's license as well as an Options and Futures license in advance of serving as an Investment Executive for personal accounts with a Bay Street Investment House. He has served on numerous Boards including the Peel Regional Police Services Board, and the Trillium Hospital Foundation. At this time, Mr. Iannicca is a Councillor for the City of Mississauga.

Mr. Chorlton holds a Bachelor of Arts degree with an Economics major from the University of Manchester. Mr. Chorlton's business experience includes thirty-two years with Hydro One and its predecessor, Ontario Hydro, with fifteen of those years in senior Finance positions, including financial forecasting, power costing, corporate budgeting and management auditing. He was also appointed the first Ethics Officer of Ontario Hydro following the development of a new Code of Business Conduct and is a past Chair of the Canadian Centre for Ethics and Corporate Policy.

Enersource Corporation is not relying on any exemptions contained within section 2.4 or Part 8 of Multilateral Instrument 52-110, dated March 26, 2004 and revised June 17, 2005.

Enersource Corporation's Audit Committee, per its mandate, must approve all audit and non-audit engagements with Enersource Corporation's external auditors, and as such, no pre-approval policies and procedures are in place.

External Auditor Service Fees:

(a) Audit Fees
The audit fees billed by KPMG for the fiscal year 2006 were $74 and the audit fees billed by KPMG for the fiscal year 2005 were $71.

(b) Audit-Related Fees
The total audit-related fees billed by KPMG for the fiscal year 2006 were $18. The audit-related fees billed in 2006 pertained to quarterly reviews of Enersource's interim financial statements.

The total audit-related fees billed by KPMG for the fiscal year 2005 were $12. The audit-related fees billed in 2005 pertained to quarterly reviews of Enersource's interim financial statements.

(c) Tax Fees
The tax fees billed by KPMG for the fiscal year 2006 were $22. These fees pertained to the preparation of tax returns for Enersource Corporation and its subsidiaries.

The tax fees billed for the fiscal year 2005 were $20. These fees pertained to the preparation of tax returns for Enersource Corporation and its subsidiaries.

(d) All Other Fees
Other fees billed by KPMG in fiscal 2006 were $8.

No other fees were billed by KPMG in fiscal 2005.

Enersource Corporation is relying on the exemption provided in section 6.1 of the Instrument relating to the required disclosures for venture issuers.

Question 2

Reference SEC I/R #5.

Please file the full Strategic Plan for Enersource Corporation.

Question sent Friday Nov 23, 2:20 pm

[Ref:J/D/7] Please file the full document, starting from page 1-1 and going to the end without omitting any pages.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 3

Reference SEC I/R #8.

Please file both the agreement for the construction work and the shareholders' agreement.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/10] Please file the agreement requested.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 4

Reference SEC I/R #9.

Please provide the 2007 Enersource Corporation budget referred to.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/11] Please provide the full 2007 budget for Enersource Corporation.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 5

Reference SEC I/R #10.

Please summarize the prepayment provisions for the bonds and provide an excerpt from the bond documentation that includes all of the actual provisions for prepayment.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/12] Please provide the prepayment formula and a copy of each clause in the borrowing documents referring to same.

Response:

See attachment.

PROSPECTUS SUPPLEMENT

To the Short Form Base Shelf Prospectus Dated April 25, 2001

This prospectus supplement (the "Supplemental Prospectus"), together with the short form base shelf prospectus dated April 25, 2001 (the "Shelf Prospectus") to which it relates, as amended or supplemented, and each document deemed to be incorporated by reference into the Shelf Prospectus, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

These securities have not and will not be registered under the United States Securities Act of 1933, as amended, and, subject to certain exceptions, may not be offered or sold within the United States or to United States persons unless registered under that Act and applicable state securities laws or an exemption from such registration is available.

New Issue

April 26, 2001

Borealis

BOREALIS INFRASTRUCTURE TRUST

$290,000,000

6.27 % Borealis-Enersource Series Bonds
Tranche 1, Due May 3, 2011
Special Purpose Limited Recourse Debt

Borealis Infrastructure Trust may, from time to time, offer bonds in an aggregate principal amount of up to $500,000,000 during the 25 month period from the date of the Shelf Prospectus. Under this Supplemental Prospectus, Borealis Infrastructure Trust is offering (the "Offering") $290,000,000 of 6.27% Borealis-Enersource Series Bonds, Tranche 1, due May 3, 2011 (the "Tranche 1 Enersource Bonds") to be issued pursuant to the Borealis-Enersource Series supplemental trust indenture (the "Enersource Series Supplemental Indenture") to the Trust Indenture (as defined in the Shelf Prospectus) and a terms supplement to the Enersource Series Supplemental Indenture respecting the Tranche 1 Enersource Bonds (the "Tranche 1 Terms Supplement"). The proceeds from the Tranche 1 Enersource Bonds will be advanced to Enersource Corporation ("Enersource") pursuant to the Credit Agreement (as defined in the Shelf Prospectus) so that Enersource may: (i) acquire from Mississauga existing demand promissory notes of Enersource Hydro Mississauga, which promissory notes will be refinanced to reflect the terms of the Enersource Loans; and (ii) for general corporate purposes. (See "Use of Proceeds".)

It is a condition of closing of this Offering that the Tranche 1 Enersource Bonds be assigned a rating of "AA-" by S&P and "A" by DBRS.

The Tranche 1 Enersource Bonds will be Borealis Infrastructure Trust's direct obligations secured by a first ranking charge on collateral comprised of the Enersource Loans, the benefit of the Credit Agreement and the Enersource Security. (See "Details of the Offering - Security".) The Enersource Loans are unsecured obligations of Enersource. **Recourse in respect of all tranches of the Enersource Bonds, including the Tranche 1 Enersource Bonds, will be limited to such collateral and will not extend to any of Borealis Infrastructure Trust's other assets or undertakings**. The assets securing the Enersource Bonds will not comprise security for any other series of bonds that Borealis Infrastructure Trust has issued or will issue.

Enersource's earnings before interest for the 12 months ended December 31, 2000 was less than the annual interest requirements for the Tranche 1 Enersource Bonds. This deficiency arises from year 2000 revenues of Enersource Hydro Mississauga that were regulated and derived without contemplation of interest expense on indebtedness. Enersource's pro forma earnings are greater than the interest expense on the Tranche 1 Enersource Bonds. (See "Earnings Coverage Ratio".)

The Tranche 1 Enersource Bonds will not be listed on any securities exchange. The interest rate, offering price and other features of the Tranche 1 Enersource Bonds have been determined by negotiations between the Issuer and the Underwriters. **There is no market through which these securities may be sold and the purchasers may not be able to resell securities purchased under the Shelf Prospectus.**

In the opinion of Meighen Demers LLP, counsel to the Issuer, Fraser Milner Casgrain LLP, counsel to Enersource, and Torys, counsel to the Underwriters (as defined below), the Tranche 1 Enersource Bonds, if outstanding on the date of this Supplemental Prospectus, would qualify for investment, or their purchase would not be prohibited, under certain statutes referred to under "Eligibility for Investment".

Price: 99.978% per Tranche 1 Enersource Bonds

	Price to Public	Underwriters' Fee	Proceeds to the Issuer[1]
Per $1,000 principal amount of Tranche 1 Enersource Bonds	$999.78	$7.50	$999.78
Total Offering	$289,936,200	$2,175,000	$289,936,200

(1) The expenses of the Offering estimated to be $1,895,000, together with the Underwriters' fee, will be paid by Enersource.

TD Securities Inc., Scotia Capital Inc. and BMO Nesbitt Burns Inc. (the "Underwriters"), as principals, conditionally offer the Tranche 1 Enersource Bonds, subject to prior sale, if, as and when issued by Borealis Infrastructure Trust and accepted by the Underwriters in accordance with the conditions contained in the underwriting agreement referred to under "Plan of Distribution" and subject to the approval of all legal matters on behalf of Borealis Infrastructure Trust by Meighen Demers LLP and on behalf of the Underwriters by Torys. Subscriptions for the Tranche 1 Enersource Bonds will be received subject to rejection or allotment in whole or in part and the Underwriters reserve the right to close the subscription books at any time without notice. It is expected that the Tranche 1 Enersource Bonds will be ready for delivery in book-entry form only through the facilities of The Canadian Depository for Securities Limited in Toronto on the closing which is expected to occur on or about May 3, 2001 but not later than June 3, 2001.

Borealis Infrastructure Trust is not a trust company and Borealis Infrastructure Trust does not carry on business as a trust company. Accordingly, Borealis Infrastructure Trust is not registered under the trust company legislation of any jurisdiction. The Tranche 1 Enersource Bonds are not "deposits" within the meaning of the *Canada Deposit Insurance Corporations Act (Canada)* and are not insured under the provisions of that Act or any other legislation.

TD SECURITIES INC. **SCOTIA CAPITAL INC.**

BMO NESBITT BURNS INC.

TABLE OF CONTENTS

All capitalized terms not defined in this Supplemental Prospectus shall have the meaning ascribed to them under the accompanying Shelf Prospectus.

DOCUMENTS INCORPORATED BY REFERENCE

This Supplemental Prospectus is deemed to be incorporated by reference, as of the date of this Supplemental Prospectus, into the Shelf Prospectus solely for the purpose of the Offering. Other documents are also incorporated or deemed to be incorporated by reference into the Shelf Prospectus and reference should be made to the Shelf Prospectus for full particulars.

Any statement contained in this Supplemental Prospectus or in a document incorporated or deemed to be incorporated by reference in the Shelf Prospectus will be deemed to be modified or superseded to the extent that a statement contained in this Supplemental Prospectus, or in any subsequently filed document which also is or is deemed to be incorporated by reference in the Shelf Prospectus, modifies or supersedes that statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded will not be deemed, except as so modified or superseded, to constitute a part of the Shelf Prospectus.

ELIGIBILITY FOR INVESTMENT

The eligibility of the Tranche 1 Enersource Bonds for investment by purchasers to whom any of the following statutes apply is, in certain cases, governed by criteria which such purchasers are required to establish as policies or guidelines pursuant to the applicable statute (and, where applicable, the associated regulations) and is subject to the prudent investment standards and general investment provisions they provide for. In the opinion of Meighen Demers LLP, the Issuer's counsel, Fraser Milner Casgrain LLP, counsel to Enersource Corporation, and Torys, counsel to the Underwriters, subject to compliance with the foregoing, purchasers subject to the following statutes would not be precluded from investing in the Tranche 1 Enersource Bonds.

Insurance Companies Act (Canada)

Trust and Loan Companies Act (Canada)

Pension Benefits Standards Act, 1985 (Canada)

Cooperative Credit Associations Act (Canada)

Financial Institutions Act (British Columbia)

Pension Benefits Standards Act (British Columbia)

Loan and Trust Corporations Act (Alberta)

Alberta Heritage Savings Trust Fund Act (Alberta)

Employment Pension Plans Act (Alberta)

Insurance Act (Alberta)

The Pension Benefit Act, 1992 (Saskatchewan)

The Pension Benefits Act (Manitoba)

The Insurance Act (Manitoba)

The Trustee Act (Manitoba)

Pension Benefits Act (Ontario)

Loan and Trust Corporations Act (Ontario)

Trustee Act (Ontario)

An Act respecting trust companies and saving companies (Qu• bec)

Supplemental Pension Plans Act (Qu• bec)

An Act respecting insurance (Qu• bec) (in respect of insurers other than guarantee fund corporations)

Pension Benefits Act (Nova Scotia)

Trustee Act (Nova Scotia)

In the opinion of such counsel, the Tranche 1 Enersource Bonds will not be qualified investments for trusts governed by registered retirement savings plans, registered education savings plans, registered retirement income funds or deferred profit sharing plans under the *Income Tax Act (Canada)*.

SUMMARY OF THE OFFERING

Issue:	6.27% Borealis-Enersource Series Bonds Tranche 1
Aggregate Principal Amount:	$290,000,000
Date of Issuance:	May 3, 2001
Maturity Date:	May 3, 2011 (the "Maturity Date")
Price per Bond:	$99.978 (per $100 principal amount)
Interest Rate:	6.27% per annum, calculated semi-annually in arrears
Interest Payment Dates:	May 3 and November 3 of each year until maturity, commencing November 3, 2001
Payment of Principal:	The full principal amount and all accrued and unpaid interest will be payable on the Maturity Date.
Optional Prepayment:	The Tranche 1 Enersource Bonds may be prepaid in whole or in part by Borealis Infrastructure Trust upon 30 business days' prior notice to the holders of Tranche 1 Enersource Bonds and upon deposit with the bondholders' trustee of an amount equal to the prepayment price, calculated as the aggregate of: (a) the interest accrued and unpaid on the principal amount of the Tranche 1 Enersource Bonds remaining unpaid; and (b) the greater of (i) the aggregate principal amount of the Tranche 1 Enersource Bonds remaining unpaid, and (ii) the net present value of the scheduled principal and interest payments on the Tranche 1 Enersource Bonds had the Tranche 1 Enersource Bonds remained outstanding until the Maturity Date, calculated by discounting at the Canada bond yield (for a bond having a term equal to the remaining term of the Tranche 1 Enersource Bonds), as determined in accordance with the Enersource Series Supplemental Indenture and the applicable Terms Supplement, at the time of prepayment plus 15 basis points.
Ratings:	S&P: AA- DBRS: A
Risk Factors:	An investment in the Tranche 1 Enersource Bonds is subject to a number of risk factors. Prospective purchasers should consider all of the information set forth in this Supplemental Prospectus and the Shelf Prospectus to which it relates, including the discussion set forth under "Risk Factors" in the Shelf Prospectus.
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DETAILS OF THE OFFERING

Capitalized terms used but not defined in this section shall have the meanings specified in the Trust Indenture, the Enersource Series Supplemental Indenture or the Tranche 1 Terms Supplement. Reference should be made to these documents for a full description of such terms and conditions, copies of which may be inspected at the Issuer's offices, Suite 1150, 11 King Street West, Toronto, Ontario and the offices of its counsel, Meighen Demers LLP, Suite 1100, Merrill Lynch Canada Tower, 200 King Street West, Toronto, Ontario, during normal business hours during the period of distribution of the Tranche 1 Enersource Bonds. The following summary of certain material attributes and characteristics of the Tranche 1 Enersource Bonds does not purport to be complete. Reference is made to the Shelf Prospectus for a summary of the other material attributes and characteristics applicable to all of the Enersource Bonds and to the Trust Indenture and the Enersource Series Supplemental Indenture for the full text of attributes and characteristics related to all of the Enersource Bonds.

The securities offered hereunder are $290,000,000 principal amount of 6.27% Borealis-Enersource Series Bonds, Tranche 1 due May 3, 2011. The Tranche 1 Enersource Bonds are governed by the Trust Indenture and the Enersource Series Supplemental Indenture.

General

The Tranche 1 Enersource Bonds will be issued pursuant to the Enersource Series Supplemental Indenture and the Tranche 1 Terms Supplement to be dated the date of issuance of the Tranche 1 Enersource Bonds between the Issuer and the Trustee providing for the creation and issue of the Tranche 1 Enersource Bonds.

Principal and Interest

The Tranche 1 Enersource Bonds will be dated May 3, 2001, will bear interest at the rate of 6.27% per annum, calculated semi-annually in arrears, from and including the date of issue of such Tranche 1 Enersource Bonds, payable in arrears on May 3 and November 3 of each year commencing on November 3, 2001, and will mature on May 3, 2011. The full principal amount and all accrued and unpaid interest on the Tranche 1 Enersource Bonds will be payable on the Maturity Date.

Optional Prepayment

The Tranche 1 Enersource Bonds may be prepaid in whole or in part by Borealis Infrastructure Trust upon 30 business days' prior notice to the holders of Tranche 1 Enersource Bonds and upon deposit with the bondholders' trustee of an amount equal to the prepayment price, calculated as the aggregate of: (a) the interest accrued and unpaid on the principal amount of the Tranche 1 Enersource Bonds remaining unpaid; and (b) the greater of (i) the aggregate principal amount of the Tranche 1 Enersource Bonds remaining unpaid, and (ii) the net present value of the scheduled principal and interest payments on the Tranche 1 Enersource Bonds had the Tranche 1 Enersource Bonds remained outstanding until the Maturity Date, calculated by discounting at the Canada bond yield (for a bond having a term equal to the remaining term of the Tranche 1 Enersource Bonds), as determined in accordance with the Enersource Series Supplemental Indenture and the applicable Terms Supplement, at the time of prepayment plus 15 basis points.

Ranking

The Tranche 1 Enersource Bonds will be the Issuer's direct, secured obligations. The Tranche 1 Enersource Bonds, will rank equally, without preference, priority or distinction, with the Enersource Bonds of each other tranche issued pursuant to the Shelf Prospectus.

Security

The Enersource Bonds will be direct obligations of the Issuer secured by (with recourse limited to) the Enersource Loans, the benefit of the Credit Agreement and the Enersource Security. Security granted in respect of any tranche of Enersource Bonds shall be held for the *pari passu* benefit of the entire series of Enersource Bonds. Under the Trust Indenture, the Issuer is entitled to issue additional series of bonds. Each additional series of bonds issued pursuant to the provisions of the Trust Indenture and the applicable supplemental trust indenture will be the

Issuer's limited recourse obligations, separately secured by collateral segregated and identified as being applicable only to such series of bonds. Accordingly, there will be no cross-collateralization between any series of bonds, and holders of one series of bonds will have no claim against the Issuer except to the extent such claims may be satisfied out of the collateral applicable to such series of bonds.

The recourse of the Trust Company of Bank of Montreal, as bondholders' trustee, on behalf of the holders of Enersource Bonds, for the performance of the Issuer's obligations under the Trust Indenture and any Enersource Series Supplemental Indenture will be limited to the Issuer's right, title and interest in and to the Enersource Loans, the benefit of the Credit Agreement and the Enersource Security. No recourse may be had to any other assets or undertaking of Borealis Infrastructure Trust or of Borealis Infrastructure Trust Management Inc., as trustee.

Form, Denomination and Transfer

The Tranche 1 Enersource Bonds will be issued in "book-entry only" form and must be purchased or transferred through participants in the CDS depository service, which include Canadian securities brokers and dealers, banks and trust companies. CDS holds securities deposited by its participants and facilitates the settlement among participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in participants' accounts, thus eliminating the need for physical movement of securities certificates. On the date of closing of the sale of Tranche 1 Enersource Bonds, Borealis Infrastructure Trust will cause a global certificate representing the Tranche 1 Enersource Bonds to be delivered to, and registered in the name of, CDS or its nominee.

Except as described in the Shelf Prospectus, a purchaser acquiring a beneficial interest in a Tranche 1 Enersource Bond will not be entitled to a certificate or other instrument from the Issuer or CDS evidencing its interest in the Tranche 1 Enersource Bond, and such purchaser will not be shown on the records maintained by CDS except through a book-entry account of a participant acting on behalf of the purchaser. Purchasers will receive a customer confirmation of purchase from the participant from which the Tranche 1 Enersource Bond is purchased in accordance with the practices and procedures of that participant. The practices of participants may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS will be responsible for establishing and maintaining book-entry accounts for its participants having interests in the Tranche 1 Enersource Bonds.

Payments of Principal and Interest

Borealis Infrastructure Trust will make payments of principal and interest on each Tranche 1 Enersource Bond to CDS or its nominee, as the case may be, as the registered holder of the Tranche 1 Enersource Bond, and understands that such payments will be forwarded by CDS or its nominee, as the case may be, to participants in the CDS depository service. As long as CDS or its nominee is the registered owner of the Tranche 1 Enersource Bonds, CDS or its nominee, as the case may be, will be considered the sole owner of the Tranche 1 Enersource Bonds for the purpose of receiving payments on the Tranche 1 Enersource Bonds. Borealis Infrastructure Trust's responsibility and liability in respect of the Tranche 1 Enersource Bonds is limited to making payment of any principal of and interest due on the Tranche 1 Enersource Bonds to CDS or its nominee.

USE OF PROCEEDS

Borealis Infrastructure Trust is offering the Tranche 1 Enersource Bonds to raise proceeds to be advanced to Enersource pursuant to the Credit Agreement. Enersource will use the net proceeds of the Tranche 1 Enersource Bonds: (i) to acquire from Mississauga the existing demand promissory notes of Enersource Hydro Mississauga, which promissory notes will be refinanced to reflect the terms of the Enersource Loans; and (ii) for general corporate purposes.

ENERSOURCE LOAN

The interest rate, payment dates and maturity of the Enersource Loan applicable to the Tranche 1 Enersource Bonds are described in Schedule A to this Supplemental Prospectus. The terms of the Enersource Loan with respect to the Tranche 1 Enersource Bonds have been established on a basis which entitles the Issuer to receive payments on such dates and in such amounts as are necessary to satisfy its payment obligations in respect of the Tranche 1 Enersource Bonds and to pay its ongoing costs arising from the Offering.

CREDIT RATINGS

It is a condition of the issuance of the Tranche 1 Enersource Bonds that they be rated "AA-" by S&P and "A" by DBRS as of the date of issuance.

None of the above ratings should be construed as a recommendation to buy, sell or hold the Tranche 1 Enersource Bonds offered under this Supplemental Prospectus. Any of the ratings may be revised or withdrawn at any time by the respective rating organization.

CAPITALIZATION

The following table sets out the consolidated capitalization of Enersource as at December 31, 2000, before and after giving effect to this Offering. This table should be read in conjunction with the consolidated financial statements of Enersource, including their notes, and "Management's Discussion and Analysis of Financial Position and Results of Operations for Enersource" appearing in the Shelf Prospectus. Figures in this table are in thousands of dollars.

Enersource

Designation	Amount Outstanding as at December 31, 2000	Amount Outstanding as at December 31, 2001 after Giving Effect to this Offering and Proceeds of Application
Liabilities		
Notes Payable	$269,214	Nil
Enersource Loans	Nil	$289,936
Total Debt	269,214	289,936
Shareholders' Equity		
Class A shares	155,628	155,628
Class B shares	1	1
Class C shares	20,062	20,062
Retained earnings	4,811	4,811
Total shareholders' equity	180,502	180,502
Total Capitalization	$449,716	$470,438

EARNINGS COVERAGE RATIO

Enersource's pro forma interest requirements, after giving effect to the issue of the Tranche 1 Enersource Bonds by Borealis Infrastructure Trust and the advance of the related Enersource Loan under the Credit Agreement, amounted to $18,183,000 for the 12 months ended December 31, 2000. Enersource's earnings before interest for the 12 months then ended was $14,037,000, which is 0.77 times Enersource's interest requirements for this period. The dollar amount of the coverage deficiency is $4,146,000. This deficiency arises from year 2000 revenues of

Enersource Hydro Mississauga that were regulated and derived without contemplation of interest expense on indebtedness. Enersource's pro forma earnings are greater than the interest expense on the Tranche 1 Enersource Bonds.

PLAN OF DISTRIBUTION

Under an agreement dated April 26, 2001 (the "Underwriting Agreement") between Borealis Infrastructure Trust and the Underwriters, Borealis Infrastructure Trust has agreed to sell and the Underwriters have agreed to purchase on May 3, 2001 or such later date as may be agreed upon by the parties but in any event no later than June 3, 2001, subject to compliance with all necessary legal requirements and the terms and conditions contained in the Underwriting Agreement, all but not less than all of the $290,000,000 principal amount of the Tranche 1 Enersource Bonds at a price equal to 99.978% of their principal amount payable in cash to the Issuer against delivery of the Tranche 1 Enersource Bonds. The obligations of the Underwriters under the Underwriting Agreement may be terminated in their discretion on the basis of their assessment of the state of the financial markets and upon the occurrence of certain stated events. The Underwriters are, however, obligated to take up and pay for all of the Tranche 1 Enersource Bonds if any of the Tranche 1 Enersource Bonds are purchased under the Underwriting Agreement. The obligations of the Underwriters under the Underwriting Agreement are several as to their respective underwriting commitments. The Underwriters will be paid an aggregate fee of $2,175,000 by Enersource on account of services rendered in connection with the offering, issue and sale of the Tranche 1 Enersource Bonds. The obligations of the Underwriters under the Underwriting Agreement may be terminated upon the occurrence of certain stated events.

The Bonds have not been and will not be registered under the *United States Securities Act of 1933* (the "1933 Act") or any state securities laws and may not be offered or sold within the United States or to U.S. persons unless registered under the 1933 Act and applicable state securities laws or an exemption therefrom is available.

This Supplemental Prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the Tranche 1 Enersource Bonds in the United States. In addition, until 40 days after the commencement of the offering of the Tranche 1 Enersource Bonds, an offer or sale of the Tranche 1 Enersource Bonds within the United States by any dealer, whether or not participating in the Offering, may violate the registration requirements of the 1933 Act if such offer or sale is made otherwise than in accordance with Rule 144A under the 1933 Act.

Subscriptions for the Tranche 1 Enersource Bonds will be received subject to rejection or allotment in whole or in part by the Underwriters and the right is reserved by the Underwriters to close subscriptions at any time without notice.

PROMOTER

Borealis Funds Management Ltd. will be paid a structuring fee of 0.15% of the principal amount of the Tranche 1 Enersource Bonds.

LEGAL MATTERS

Certain legal matters in connection with the Tranche 1 Enersource Bonds offered hereby will be passed upon for the Issuer by Meighen Demers LLP, Toronto, Ontario, for Enersource by Fraser Milner Casgrain LLP, Toronto, Ontario and for the Underwriters by Torys, Toronto, Ontario.

CERTIFICATE OF THE UNDERWRITERS

DATE: April 26, 2001

To the best of our knowledge, information and belief, the short form prospectus, together with the documents incorporated in the prospectus by reference, as supplemented by the foregoing, will, as of the date of the last supplement to the prospectus relating to the securities offered by the prospectus and the supplement(s), constitute full, true and plain disclosure of all materials facts relating to the securities offered by the prospectus and the supplement(s), as required by the securities legislation of each province of Canada, and will not contain any misrepresentation likely to affect the value or the market price of the securities to be distributed.

TD SECURITIES INC.

By: (Signed) SCOTT C. NORTHEY

SCOTIA CAPITAL INC.

By: (Signed) PHILIP I. LIEBERMAN

BMO NESBITT BURNS INC.

By: (Signed) BRADLEY J. HARDIE

The following includes the names of every person having an interest, directly or indirectly, to the extent of not less than 5% in the capital of:

TD SECURITIES INC.: a wholly owned subsidiary of a Canadian chartered bank;

SCOTIA CAPITAL INC.: an indirect wholly owned subsidiary of a Canadian chartered bank; and

BMO NESBITT BURNS INC.: a wholly owned subsidiary of BMO Nesbitt Burns Corporation Limited, an indirect majority-owned subsidiary of a Canadian chartered bank.

**SCHEDULE A – TERMS OF THE TERM LOAN
TO BE ADVANCED IN RESPECT OF
THE TRANCHE 1 ENERSOURCE BONDS OFFERING**

Principal Amount:	$290,000,000(1)
Term:	10 years
Maturity Date:	May 3, 2011
Interest Rate:	6.29%(2)
Payment Dates:	2 business days prior to payment dates on Tranche 1 Enersource Bonds
Optional Prepayment:	As for Tranche 1 Enersource Bonds

(1) Actual loan proceeds advanced to Enersource will be $289,936,200.

(2) The interest rate on the Enersource Loan is higher by 2 basis points than the interest rate on the Tranche 1 Enersource Bonds to provide sufficient cash flow to enable the Issuer to pay expected ongoing costs arising from this Offering.

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Question 6

Reference SEC I/R #11.

Please provide calculations as requested. If you cannot replicate the DBRS calculations, please advise.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/13] Please provide the explanation requested, or calculate and provide what the applicant believes was the increase in OM&A per customer for each of 2006, 2007, and 2008.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 7

Reference SEC I/R #13.

The source of the statement is the Enersource Corporation 2006 annual report, page 2 & 11. Please provide evidence that these statements are correct.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/15] The source of the statement appears to be the following statement on page 11 of the 2006 Annual Report of Enersource Corporation: "Notably, we are also one of the lowest cost electricity distributors in Ontario". Please provide whatever evidence is in the possession of the applicant that this statement is correct. If no evidence is available, please provide the basis on which the statement was made in a formal disclosure document.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 8

Reference SEC I/R #14.

Please provide evidence that the unregulated businesses did not have a material impact on your financial profile at that time. Please provide a copy of the first rating agency report on the bond issue (or the proposed bond issue, if the report was prior to issuance).

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/16] Please provide evidence that the existence of higher risk unregulated businesses did not have an impact on the rate at which the bonds were issued.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Enersource Corporation

Current Report: May 22, 2002
Previous Report: May 14, 2001

Matthew Kolodzie, P.Eng., Geneviève Lavallée, CFA
416-593-5577 x2296/x2277
mkolodzie@dbrs.com

RATING

Rating	Trend	Rating Action	Debt Rated
"A"	Stable	Confirmed	Corporate Debt

RATING HISTORY	Current	2001	2000	1999	1998	1997
Corporate Debt	"A"	"A"	NR	NR	NR	NR

COMMENTARY

The rating for Enersource Corporation ("Enersource" or "the Company") continues to be supported by the following factors. (1) Its regulated electricity distribution subsidiary, Enersource Hydro Mississauga ("EMH"), accounts for almost all of Enersource's operating income and 98% of its fixed assets. Regulated electricity distribution provides for a high degree of earnings and cash flow stability. (2) A well-diversified customer base with a moderate load growth rate will contribute to stable long-term earnings growth. (3) Operating cash flows and current cash balances will be sufficient to finance its internal requirements over the next three years. As a result, its balance sheet will remain strong, and key cash flow and coverage ratios should improve significantly. (4) The Company's shareholders are very strong financially and may provide equity injections to finance non-regulated activities such that the current capital structure is maintained.

The rating is currently constrained by a number of challenges largely related to industry restructuring. (1) The most important challenge the Company (and the industry) faces is political risk. As a result of the political pressures from the sharply higher electricity rates that would have resulted immediately from moving to the new regulatory environment, the Ontario Energy Board ("OEB") directed Local Distribution Companies ("LDCs") to phase in the initial rate increase required to generate the 9.88% target rate of return over a three-year period. Consequently, Enersource's profitability and interest coverage will remain weaker until rate increases are fully phased in. (2) Uncertainty exists regarding the future regulatory framework beyond 2003. It has yet to be decided if and how LDCs rate bases will be re-based, how approved ROEs will be set in the future, how deferred market transition costs will be recovered and whether productivity targets will be the same for all LDCs or be set for groups of utilities with similar characteristics. Enersource's medium-term profitability and cash flow growth will depend on how these issues are resolved. (3) Diversification beyond regulated distribution will increase business risk, although management is expected to maintain its conservative approach to investing in non-regulated activities. Over the medium term, non-regulated operations are expected to remain below 10% of consolidated assets, and similarly the impact of non-regulated activities on the stability of consolidated EBIT is expected to be minimal. (4) Financial flexibility is limited by the Company's inability to issue common equity (its equity base is limited to internal earnings growth).

RATING CONSIDERATIONS

Strengths:

- Involved primarily in the regulated electricity distribution
- Favourable franchise area
- Operating cash flows plus cash balances sufficient to cover capital expenditures over the next two years
- Financially strong parents
- Earnings growth potential from non-regulated subsidiaries

Challenges:

- Risk of political interference in the electricity sector
- Uncertainty related to the future regulatory framework
- Diversifying beyond regulated distribution
- Ability to meet performance improvement targets
- Lack of access to the public equity markets

FINANCIAL INFORMATION

	For the years ended December 31					
	2002P	2001	2000	1999	1998	1997
Fixed charges coverage (times)	1.86	1.12	1.51	59.29	45.07	-
% adjusted debt in capital structure	61.4%	62.1%	59.9%	-	-	-
Cash flow/total adjusted debt (times)	0.12	0.09	0.11	-	-	-
Cash flow/capital expenditures (times)	0.95	0.85	1.12	1.77	1.48	1.02
Operating cash flow ($ millions)	37.5	28.9	30.6	37.2	31.1	24.9
Operating margin	35.0%	29.6%	25.3%	27.9%	21.1%	9.9%
Return on average equity	3.6%	1.0%	1.4%	3.0%	2.1%	1.0%
Electricity throughputs (millions kWh)	7,395	7,249	7,002	6,821	6,505	6,288
Customer base	165,190	163,582	159,724	153,693	149,197	144,497

THE COMPANY

Enersource Corporation is a holding company that owns Enersource Hydro Mississauga ("EHM"), a regulated electricity distribution company, and Enersource Services Inc., a non-regulated holding company. Enersource Services Inc. consists of three wholly owned subsidiaries: (1) Enersource Telecom, a fibre-optic leasing company; (2) Enersource Hydro Mississauga Services, which provides utility solutions services to the utility sector, water heater rental/leasing, and is a 57% shareholder of First Source a retail electricity marketing company (43% held by Veridian Corporation); and (3) Enersource Technologies, which provides engineering and construction services. Enersource Corporation is 90%-owned by the City of Mississauga (see separate report - Regional Municipality of Peel) and 10%-owned by BPC Energy Corporation, a subsidiary of Ontario Municipal Employees Retirement System.

Dominion
Bond Rating Service Limited
200 King Street West, Suite 1304
Sun Life Centre, West Tower, P.O. Box 34
Toronto, Ontario, Canada M5H 3T4

Telephone 416-593-5577
Fax 416-593-8432
Website www.dbrs.com

May 2, 2001

Michael Feldman/Cheryl Graden
Torys
Suite 3000
Maritime Life Tower
Box 270, TD Centre
Toronto, Ontario
M5K 1N2

Fax No: (416) 865-7380

Re: <u>Borealis-Enersource Series Bonds</u>

Dominion Bond Rating Service Limited ("DBRS") confirms the Borealis-Enersource Series Bonds at "A". We understand that the points we have raised will be addressed by letters of undertaking from the various parties.

As is customary, the rating is subject to timely receipt of notices and documentation under the program documentation for Borealis Infrastructure Trust.

Yours truly,
DOMINION BOND RATING SERVICE LIMITED

Mark Adams, Vice President

c.c. Jacques Demers
Fax No: (416) 977-5239

The Exchange Tower
130 King Street West
Suite 2750, PO Box 486
Toronto, ON M5X 1E5
Tel 416 202 6001
Fax 416 364 5336

Thomas Connell
Managing Director
Canadian Ratings

Standard & Poor's
A Division of The McGraw-Hill Companies

May 2, 2001

James Gillis
TD Securities Inc.
55 King St. @ Bay St., 8th Floor
P.O. Box 1, Toronto Dominion Bank Tower
Toronto, ON
M5K 1A2

Re: C$290 million 6.27% Borealis - Enersource Series Bonds, Tranche 1, due 2011

Dear Mr. Gillis:

Pursuant to your request, Standard & Poor's has reviewed the information presented to us by Enersource, Hydro Mississauga and has assigned a rating of "AA-" to the above-captioned issue. If you have any questions relating to this rating, we will be pleased to answer them.

Standard & Poor's relies on the issuer, it's counsel, accountants and other experts for the accuracy and completeness of the information submitted in connection with the rating process and surveillance. Accordingly, we should receive all pertinent information. In the event that we do not receive such information, the rating may be at risk of withdrawal.

This letter constitutes Standard & Poor's permission to disseminate the above-assigned rating to interested parties. You understand that Standard & Poor's has not consented to, and will not consent to, being named an "expert" under applicable securities laws. In addition, it should be understood that the rating is not a "market" rating nor a recommendation to buy, hold or sell the securities. Standard & Poor's reserves the right to advice its own clients subscribers, and the public of the rating.

We are pleased to have had the opportunity of being of service to you. If we can be of any further help, please do not hesitate to call upon us.

Very truly yours,

Thomas Connell

cc Rob Watters, Borealis Funds Management

Question 9

Reference SEC I/R #15.

We don't understand how Enersource budgets without a manual or memoranda. Please provide a more detailed description of the process.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/17] Please describe how the rules, processes, assumptions, and other aspects of the budgeting process are communicated to those in the organization responsible for budgeting.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 10

Reference SEC I/R #17.

If these numbers are not correct, please provide the correct numbers given the assumptions on the first two lines of the chart.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/19] If the numbers provided are not correct, please provide the correct numbers for the chart and show how they were calculated.

Response:

Enersource's efforts to replicate the provided data is set out below. Enersource requests that all data computed using revenue:cost ratios determined by the Cost Allocation Review – Informational Filing data be made with reference to Exhibit G/ Schedule 1/ Tab x.

Response: 17. b)

		Small School		Large School	
Customer Class		GS<50 kW		GS>50 kW	
Consumption		16000	kWh	380	kW
2007 FixedRate		29.93		74.24	
2007 Fixed Revenue		$359.16		$890.88	
2007 Variable Rate*		0.0149		4.39	
2007 Variable Revenue		$2,860.80		$20,018.40	
2007 Revenue		**$3,219.96**		**$20,909.28**	
2008 Fixed Rate		32.98		83.11	
2008 Fixed Revenue		$395.76		$997.32	
2008 Variable Rate*		0.0169		4.9662	
2008 Variable Revenue		$3,244.80		$22,645.87	
2008 Revenue		**$3,640.56**		**$23,643.19**	
Change in Revenue	('08 vs '07)	$420.60		$2,733.91	
% change in Revenue	('08 vs '07)	13.06%		13.08%	
Revenue:Cost ratio		113.60%		120.60%	
Calculated 2008 Cost		$3,204.72		$19,604.64	
Calculated "excess" revenue		-$435.84		-$4,038.56	

* excluding Regulatory Assets					

Question 11

Reference SEC I/R #26.

Please file the original business case for the current SCADA system, and any updates since, including all subsequent reports on performance against the business case. Please file the internal business case used in the approval process for the proposed integrated operating model, showing all costs and benefits (financial or otherwise) for all years.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/31] Please provide the original business case for the SCADA system as requested.

Response:

Enersource's original decision to invest in its SCADA system was not based on a business case analysis or presentation. The documentation supporting the decision no longer exists. The documents supporting the decision to invest in the Integrated Operating Model have been filed previously.

Question 12

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/32/Attach.] p. 10 Please provide the numerical data behind Figure 4A.

Response:

The numerical data can be found in the following documents:

- **Exhibit B/Schedule 3/Tab2 page 8 for 1999 – 2006**
- **Exhibit B/Schedule 3/Tab3 page 20 for 2007 – 2031**

Question 13

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/33] Please provide the full business case for the Integrated Operating Model used in making, and obtaining approval for, the decision to proceed with the project.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 14

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/33] Please provide a copy of the agreement with Toronto Hydro providing for the sharing of the cost of the CIS.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 15

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/38] Please provide details of the existing CIS, including when it was purchased, the circumstances that resulted in the vendor no longer supporting it, and how it is being used today to handle RPP and other changes in the market.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 16

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/39-40] Please advise how the five year period for CIS depreciation was determined. Please explain why the CIS was assumed to have a 30% CCA rate, when other utilities are applying the 100% CCA rate in Class 12. Please explain Enersource's understanding as to why the other distributors did not participate in the CIS purchase.

Response:

Enersource has determined that the CIS project should be treated as Operating Software which has a useful life of 5 years and is consistent with the treatment of developmental software.

The 30% CCA rate was based on Class 10's asset inclusion description which partially reads: "…general-purpose electronic data-processing equipment (e.g., personal computers) and systems software, and timber cutting and removing equipment." as assets that fall in the class.

Enersource's can not comment as to why the other distributors did not participate in the CIS purchase.

Question 17

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/41(c)] Please provide an explanation of the price discrepancies as requested.

Response: 17.

Wholesale Metering

In general, wholesale metering installations include the main & alternate meters, instrument transformers and metering enclosures. A meter only upgrade is possible should the existing instrument transformers meet the Measurement Canada approvals. As per the market rules, if the instrument transformers do not meet the Measurement Canada approvals, a temporary permission may be granted to continue the use of the non-approved instrument transformers and thus permit a 'meter only' upgrade.

Should the instrument transformers not meet Measurement Canada approvals and transformer specifications not meet the criteria for temporary permission for use, a full meter upgrade is required as per the IESO market rules. In such, the installation of fully compliant instrument transformers, main and alternate meters and enclosures is required to satisfy the rules. A full meter upgrade is equivalent to a new wholesale metering installation. Further documentation relating to the wholesale metering upgrades can be found in Exhibit C, Schedule 2, Tab 4.

In 2006, Enersource completed 8 meter only upgrades. Since the existing instrument transformers were Measurement Canada (MC) approved for use, only the meter and cabinets were upgraded. Thus the capital budget per wholesale meter was $18,660 in 2006.

For 2007, Enersource completed 6 meter only upgrades. Since the existing instrument transformers were MC approved for use, only the meter and cabinets were upgraded. Also in 2007, Enersource completed 8 full metering equipment upgrades to meet Measurement Canada and IESO Market Rules. The full metering upgrades were required as per MC and IESO Market Rules, thus Enersource installed new instrument transformers, metering enclosures and new wholesale meters to meet the IESO Market Rules and Measurement Canada regulations.

In 2008 calendar year, Enersource forecasts installation of new full wholesale metering equipment (two meters, instrument transformers, metering enclosures) at one Transmission Station. No meter only upgrades are scheduled for 2008. Thus, the capital budget per wholesale meter is $72,500 for 2008.

Conventional Meter

In regard to conventional meters, Enersource installed residential 2,928 conventional meters in 2006. As a result of the smart metering, Enersource now installs smart meters on all new residential meters and thus no residential conventional meters are included in the 2007 and 2008 figures.

Question 18

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/45(b)] Please provide all previous forecasts by Enersource of the effect of demand response programs on peak demand, and all analyses showing the cost-effectiveness of demand response programs when proposed.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 19

Reference SEC I/R #I/R #34C.

Please provide the original business case for the RTU replacement project.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/46(c)] For each of the RTU replacement programs, please provide a year by year chart that shows number replaced, capital budget/actual, O&M budget/actual, and rate base impact. Please provide a vintage chart for the existing RTUs. What is the current depreciation rate for RTUs, and what is the proposed depreciation rate for the new RTUs?

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 20

Reference SEC I/R #34D.

Please advise when the spare transformer is assumed to be used and thus added to rate base.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/47(d)] Please advise when Enersource assumes, from the point of view of rates, that the spare transformer is added to rate base. Please provide the basis for that assumption.

Response:

From the OEB's APH 410

In most cases, spare transformers and meters should be accounted for as property, plant and equipment capital assets, as it is expected that:

a) The spare transformers and meters are not intended for resale and cannot be classified as inventory in accordance with CICA publication entitled " Terminology for Accountants" Fourth Edition;
b) The spare transformers and meters have a longer period of future benefit as compared to inventory items;
c) The spare transformers and meters form an integral part of the original distribution plant by enhancing the system reliability of the original distribution plant; and
d) The spare transformers and meters provide future benefits because they are expected to be placed in service.

Question 21

Reference SEC I/R #34F.

Please detail the revenue impact of the improved reliability.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/47(f)] Please provide the revenue impact and maintenance cost impact expected for each of 2008 and 2009.

Response:

The avoided revenue and maintenance costs were not forecasted for 2008 or 2009.

Question 22

Reference SEC I/R #34I.

Please advise how much of each capital cost of a vehicle is an internal cost of EHM or EC, as opposed to a vehicle acquisition cost paid to a vehicle dealer/supplier.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/unnumbered pages between 47 and 48] Please advise how much, if any, of each vehicle cost is internal costs, overhead adders, amounts paid to affiliates, or other amounts not paid to external vehicle vendors. If the capital costs listed on these pages do not include any such amounts, please advise what, if any, of those expenses are incurred in respect of these purchases, and where they would be found/included in the application.

Response:

The cost of a vehicle is capitalized by EHM at the price we paid to the vehicle dealer/supplier. Any additional customization made to the vehicle is also capitalized.

Question 23

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/49(e)] Please provide the "corporate policies and procedures" referred to.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 24

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/61/Attach] Please provide an explanation of why the costs of the Finance function at Enersource Corporation increased by $843,000 from 2006 to 2007, a total of 27.1%.

Response:

The increases in finance between 2006 and 2007 are mainly due to increased insurance expenses of $150k, risk mitigation and compliance of $400k and manpower increases.

Question 25

Question sent Friday Nov 23, 2:20 pm

[Ref: J/B/11] Please provide the attachment to the IR response.

Response:

Please see the attached spreadsheet.

CCC#10
Enersource Hydro Mississauga
2000-2006 Capital Budget and Actual Capital Spending

	2000 Capital Budget	2000 Actual Spent	2001 Capital Budget	2001 Actual Spent	2002 Capital Budget	2002 Actual Spent	2003 Capital Budget	2003 Actual Spent
LAND	-	-	-	-	-	-	-	-
SUBSTATION EQUIPMENT	5,550,000	9,939,655	4,950,000	4,703,306	3,750,000	2,063,132	2,400,000	2,514,089
SUPERVISORY CONTROL EQUIPT.	2,000,000	5,017,527	1,900,000	696,662	1,800,000	202,646	1,500,000	1,324,726
O/H PRIMARY	7,395,000	13,933,976	8,005,000	7,390,489	8,110,000	6,806,122	7,600,000	6,784,671
U/G PRIMARY	9,350,000	17,778,193	9,700,000	10,213,140	13,100,000	10,053,784	11,300,000	10,911,517
METERS	1,300,000	2,061,811	1,135,000	993,334	1,000,000	943,594	1,000,000	746,843
GENERAL OFFICE EQUIPMENT	460,000	724,746	560,000	443,793	750,000	727,301	566,500	259,871
ROLLING STOCK & EQUIPMENT	1,771,000	476,395	1,600,000	800,415	900,000	962,303	935,000	78,865
MAJOR TOOLS & INSTR.	100,000	176,479	150,000	134,206	150,000	145,967	175,000	109,146
COMPUTER EQUIPMENT	360,000	537,300	390,000	386,294	645,000	538,335	1,750,000	1,388,798
SOFTWARE	1,208,000	2,624,386	1,446,000	7,173,357	3,433,000	6,048,285	1,596,000	1,893,312
WATER HEATERS	382,000	172,923	326,000	295,623				
OTHER	1,000,000		2,400,000		1,500,000			
	30,876,000	53,443,391	32,562,000	33,230,619	35,138,000	28,491,469	28,822,500	26,011,838

	2004 Capital Budget	2004 Actual Spent	2005 Capital Budget	2005 Actual Spent	2006 Capital Budget	2006 Actual Spent
LAND	-	-	-	-	-	-
SUBSTATION EQUIPMENT	2,400,000	2,732,276	2,400,000	2,842,996	2,875,000	3,311,437
SUPERVISORY CONTROL EQUIPT.	1,400,000	775,147	1,500,000	1,193,162	1,120,000	1,550,572
O/H PRIMARY	7,100,000	7,939,822	8,100,000	8,367,564	8,925,000	8,299,060
U/G PRIMARY	12,050,000	11,690,677	12,550,000	12,547,720	13,475,000	14,393,069
METERS	1,000,000	1,238,404	1,000,000	1,248,761	1,350,086	1,254,816
GENERAL OFFICE EQUIPMENT	1,145,000	1,060,512	1,380,000	1,604,167	1,113,500	989,770
ROLLING STOCK & EQUIPMENT	1,580,000	2,356,769	1,766,000	1,817,907	1,725,000	1,622,595
MAJOR TOOLS & INSTR.	150,000	145,330	150,000	201,986	150,000	142,507
COMPUTER EQUIPMENT	1,740,000	659,322	1,975,000	480,870	2,650,000	2,035,154
SOFTWARE	1,208,500	1,315,609	897,000	1,008,038	4,704,000	1,044,313
TOTAL	29,773,500	29,913,868	31,718,000	31,313,171	38,087,586	34,643,293
CONSERVATION & DEMAND MANAGEMENT (Funded through 3rd Tranche)	-	-	-	1,146,661	4,358,000	1,874,097

Question 26

Reference SEC I/R #27.

Please file items 7-1, 7-2, 7-3 and 7-4.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/6/Attach] With respect to this document:

a. p. 14. Please explain the large increases in SAIDI for 2005 and 2006. Please provide the forecast SAIDI for 2007 and 2008.

b. p. 18. Please show how the $5 per customer minute was calculated, given that the highest per-minute value in Table 5A is $1.30 per minute, and the next highest is $0.2356 per minute.

c. p. 24. Please provide the attachments listed.

Response

7-1 Please see the original application Exhibit B, Schedule 3, Tab 3.

7-2 Please refer to the attachment.

7-3 Please refer to the attachment.

7-4 Please see the original application Exhibit C, Schedule 5, Tab 1.

ENERSOURCE
HYDRO MISSISSAUGA
SYSTEM RELIABILITY UPDATE
2006

PREPARED BY:

DISTRIBUTION & STANDARDS DEPARTMENT

ENGINEERING & OPERATIONS DIVISION

DECEMBER 31, 2006

DEFINITIONS OF CEA RELIABILITY INDICES

- **SAIDI:**

$$\frac{\text{TOTAL CUSTOMER - MINUTES OF INTERRUPTIONS}}{\text{TOTAL CUSTOMERS SERVED}}$$

- **CAIDI:**

$$\frac{\text{TOTAL CUSTOMER – MINUTES OF INTERRUPTIONS}}{\text{TOTAL CUSTOMERS INTERRUPTED}}$$

- **SAIFI:**

$$\frac{\text{TOTAL CUSTOMER - INTERRUPTIONS}}{\text{TOTAL CUSTOMERS SERVED}}$$

- **SAIFI$^{(MI)}$:**

$$\frac{\text{TOTAL MOMENTARY - CUSTOMER INTERRUPTIONS}}{\text{TOTAL CUSTOMERS SERVED}}$$

CEA Cause Code Definitions

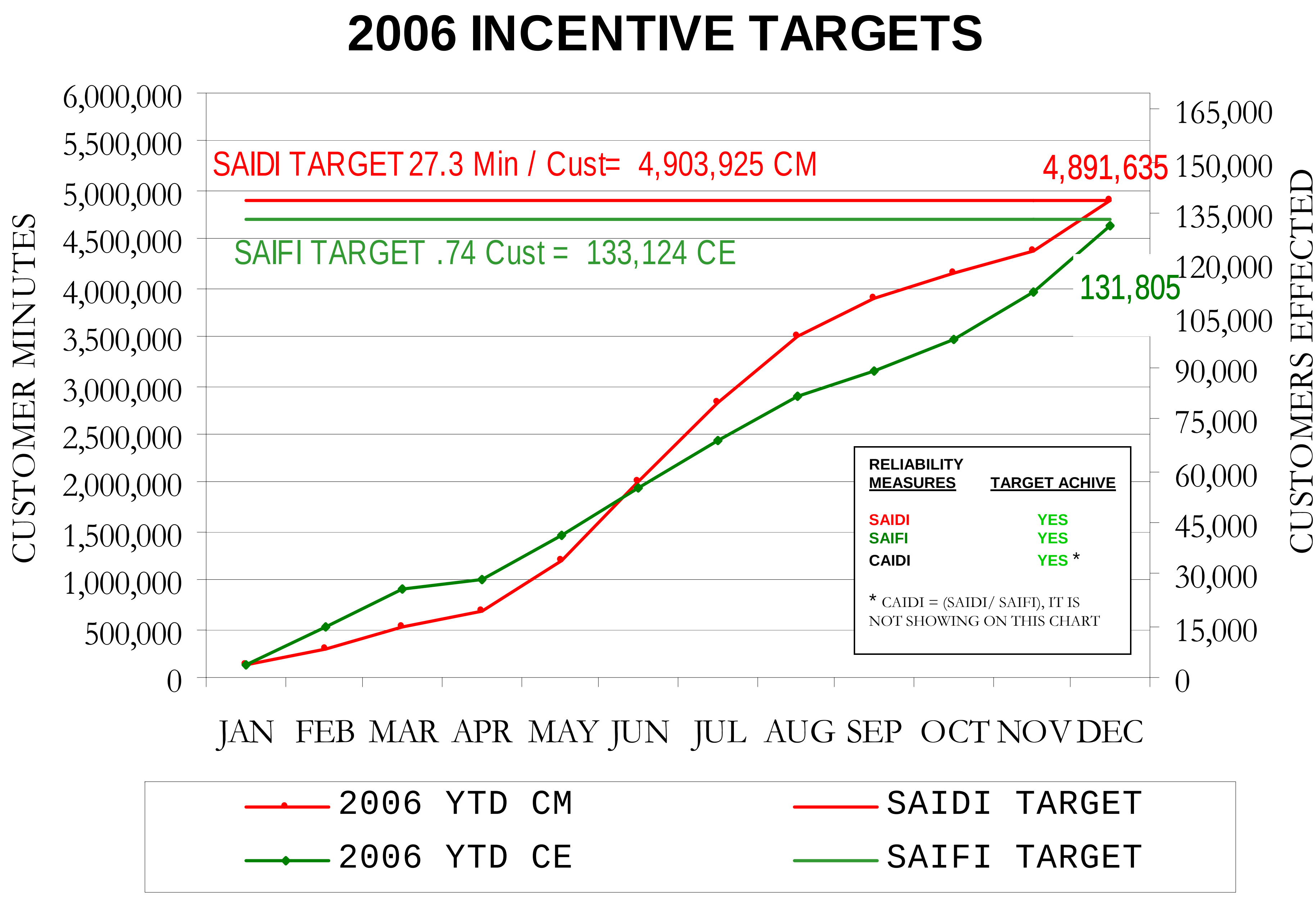
- **UNKNOWN -** no apparent cause or reason which could have contributed to the outage
- **SCHEDULED -** disconnection at a selected time for the purpose of construction or preventive maintenance
- **HYDRO ONE (LOSS OF SUPPLY) -** problems in the bulk electrical system
- **TREE CONTACTS** - faults due to tree or tree limbs contacting energized circuits
- **LIGHTNING -** lightning striking the distribution system
- **DEFECTIVE EQUIPMENT -** equipment failures due to deterioration from age or incorrect maintenance
- **ADVERSE WEATHER -** rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions
- **ADVERSE ENVIRONMENT -** equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding
- **HUMAN ELEMENT-** interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage or sabotage
- **FOREIGN INTERFERENCE** - beyond the control of the utility such as birds, animals, vehicles, vandalism, sabotage and foreign objects

TOTAL INTERRUPTIONS

	2006	2005	2004	2003
INTERRUPTIONS	451	484	430	432
CUSTOMERS	132,000	166,000	109,000	130,000
CUSTOMER MINUTES	4,892,000	5,637,000	3,875,000	4,017,000
SAIDI (Minutes)	**27.2**	**31.7**	**22.1**	**23.4**
CAIDI (Minutes)	**37.1**	**34.2**	**35.5**	**30.6**
SAIFI	**0.73**	**0.93**	**0.62**	**0.76**
SAIFI (MI)	**3.8**	**3.4**	**3.6**	**2.1**

PBR REQUIRMENTS - At a minimum equal or surpass worst results of past 3 years

Note: Data reported excludes major power blackout of August 14, 2003 resulting in 154,000,000 customer minutes



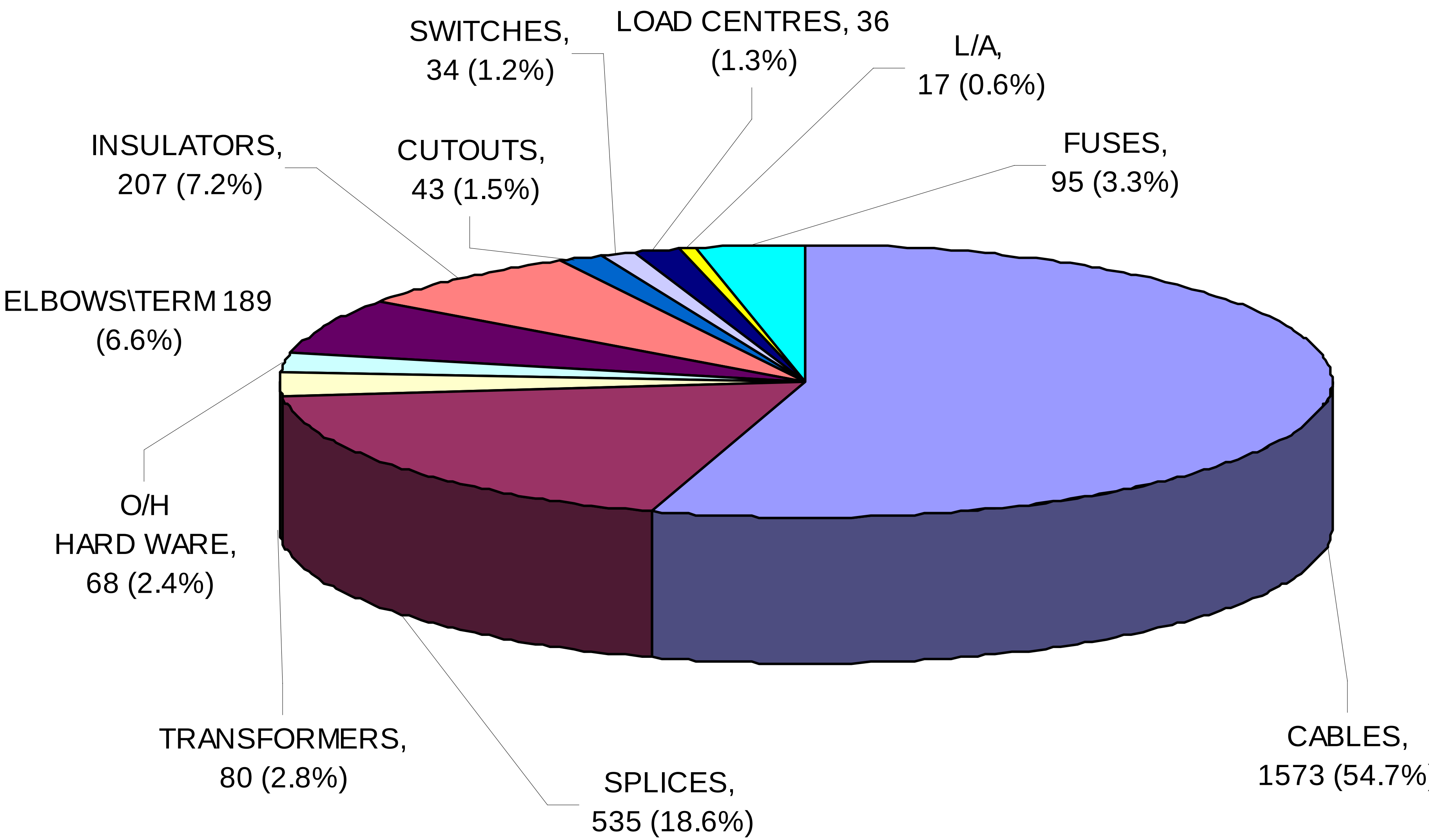
2006 INCENTIVE TARGETS
CUSTOMER MINUTES
CUSTOMERS EFFECTED
6,000,000
5,500,000
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
165,000
150,000
135,000
120,000
105,000
90,000
75,000
60,000
45,000
30,000
15,000
0
SAIDI TARGET 27.3 Min / Cust= 4,903,925 CM
SAIFI TARGET .74 Cust = 133,124 CE
4,891,635
131,805
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
RELIABILITY MEASURES
TARGET ACHIVE
SAIDI YES
SAIFI YES
CAIDI YES *
* CAIDI = (SAIDI/ SAIFI), IT IS NOT SHOWING ON THIS CHART
2006 YTD CM
2006 YTD CE
SAIDI TARGET
SAIFI TARGET

CEA - CUSTOMER MINUTES BY CAUSE

CAUSE CODE	2006	Previous 2005	3 Years 2004	Results 2003
EQUIPMENT	2,878	3,974	2,419	2,269
FOREIGN	1,130	704	947	287
TREE CONTACT	358	527	69	550
LIGHTNING	288	69	63	81
UNKNOWN	82	46	141	166
SCHEDULED	68	108	57	39
HYDRO ONE	43	52	164	394
WEATHER	26	54	14	94
HUMAN ELEMENT	12	23	1	9
ENVIRONMENT	5	79	0	128
TOTAL	4,892	5,637	3,875	4,017

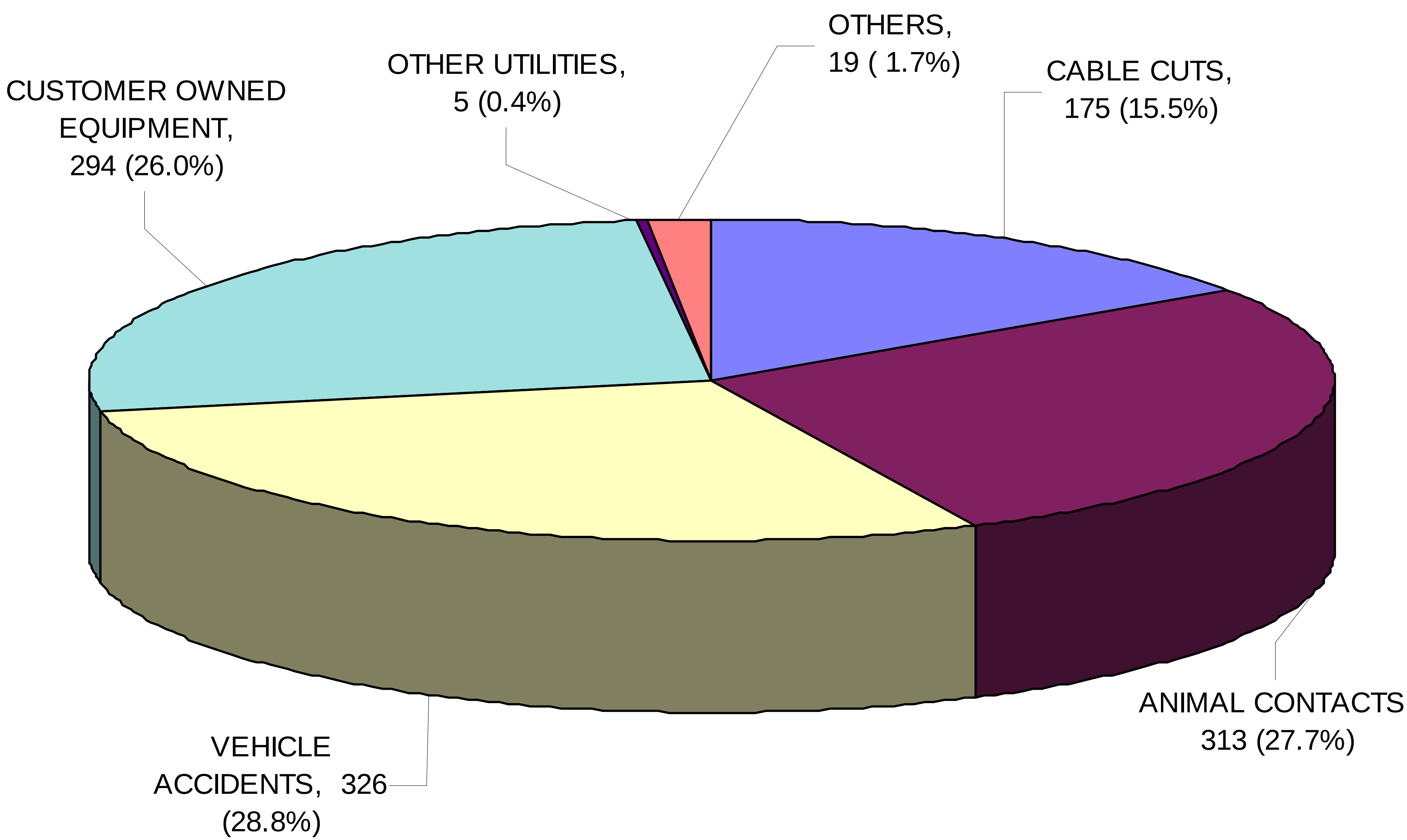
Note: Customer Minutes are in 1,000s

EQUIPMENT FAILURES



(Customer Minutes in 1000's) Percentage of the total Equipment Failures

FOREIGN INTERFERENCE



(Customer Minutes in 1000's) Percentage of the total Foreign Interference

LARGE USER RELIABILITY

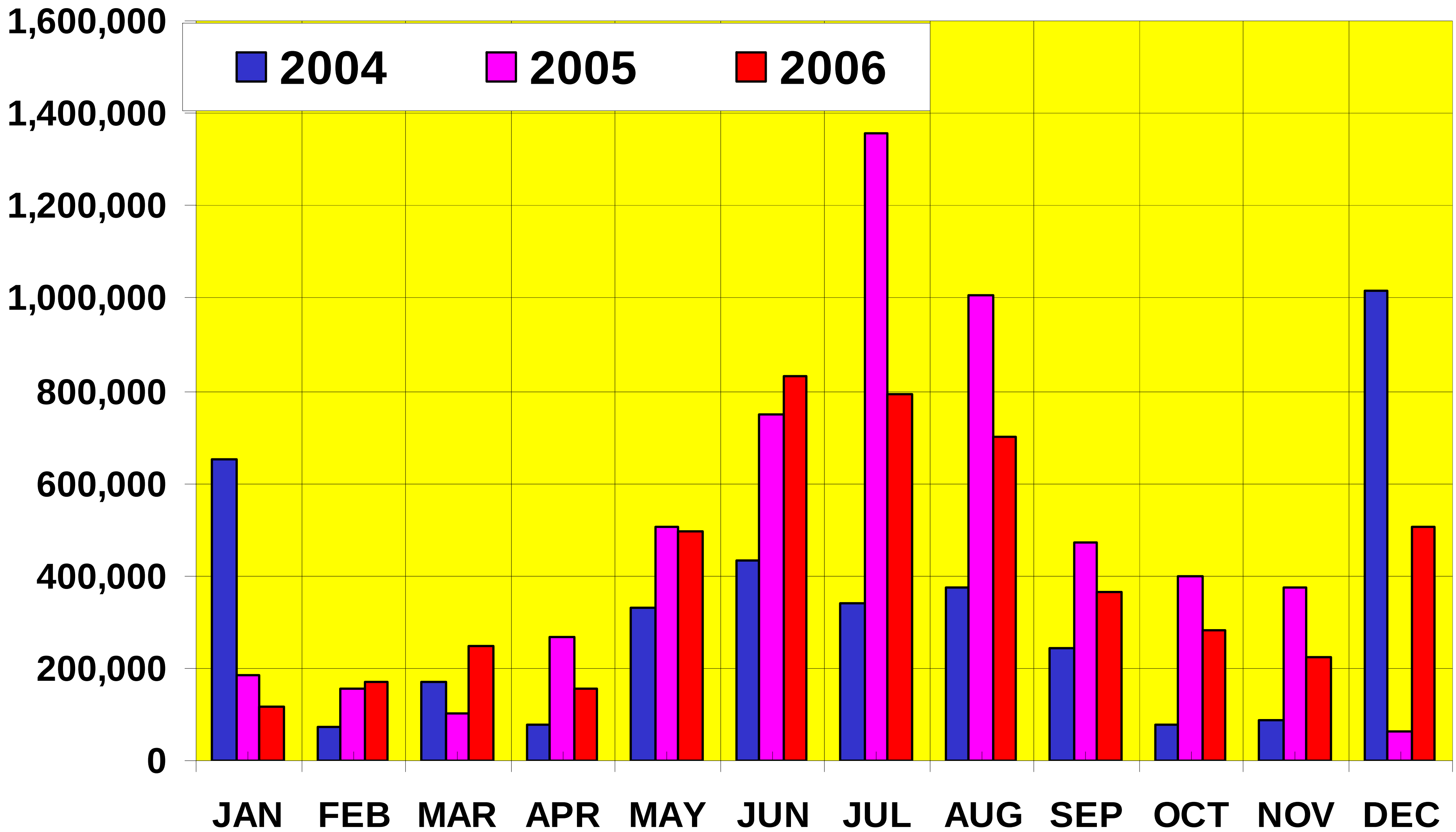
LARGE USER	PEAK DEMAND (KW)	# OF OUTAGES	TOTAL DURATION (minutes)	# OF AUTOS
PEARSON AIRPORT	38,700	3	9	17
ST LAWRENCE CEMENT	35,200	1	221	3
PETRO CANADA	19,400	0	0	4
SQUARE ONE	12,500	0	0	4
NORAMPAC	12,100	0	0	0
LAKEVIEW SEWAGE	8,900	0	0	4
CLEAN WATER AGENCY	8,800	1	740	2
STACKPOLE	7,200	0	0	2

SUMMARY OF MAJOR INTERRUPTIONS (>50,000 C.M.)

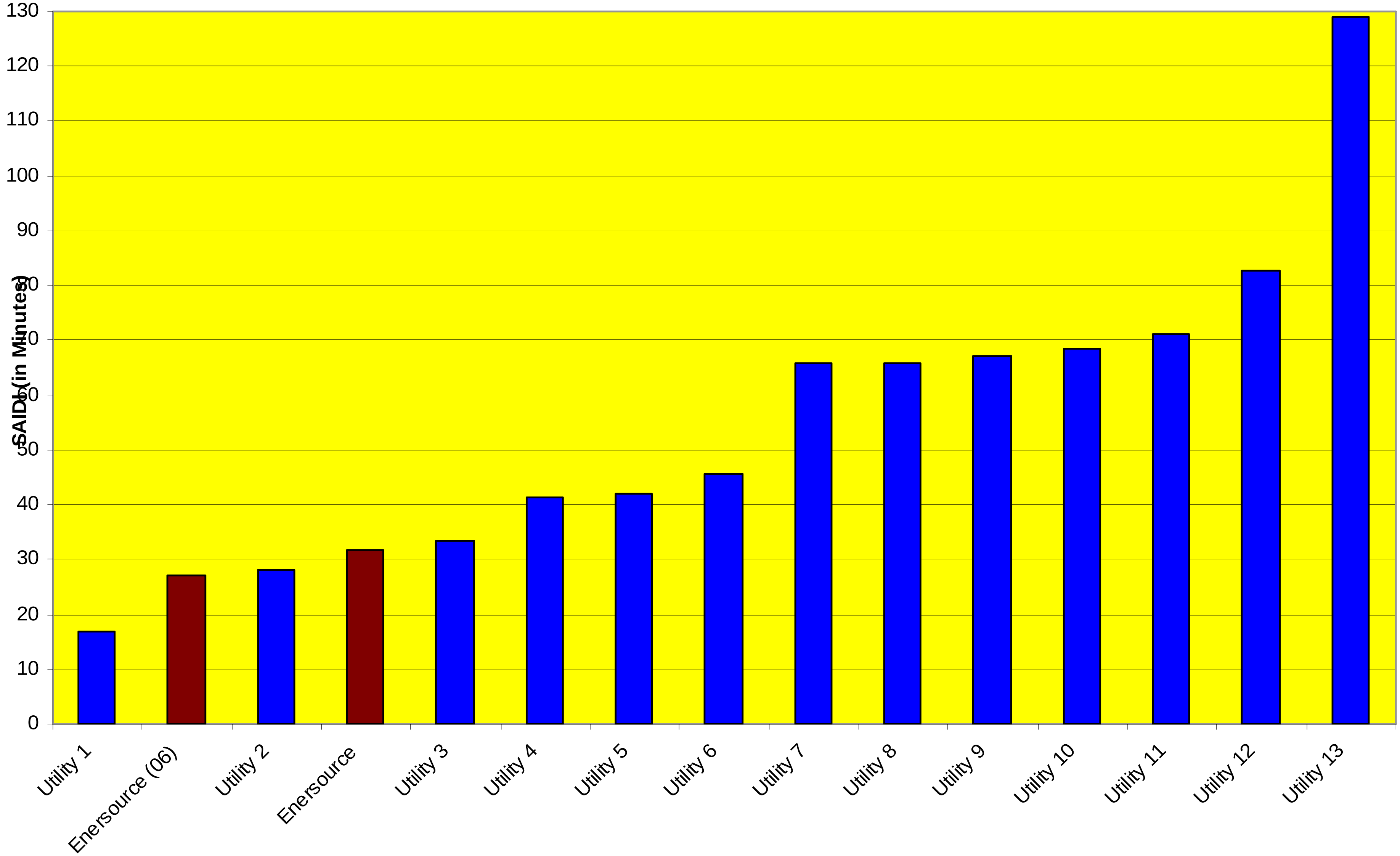
NUMBER & TYPE OF OUTAGE	CUSTOMER MINUTES
• (5) SPLICE FAILURE	428,436
• (4) CABLE FAILURE	367,429
• (2) CUSTOMER OWN EQUIPMENT	283,250
• (2) LIGHTNING	264,095
• (2) INSULATOR FAILURE	207,309
• (1) VEHICLE ACCIDENT	136,156
• (1) ELBOW FAILURE	91,154
• (1) ANIMAL CONTACT	89,945
• (1) TREE CONTACT	52,780

2006 TOTALS	19 INTERRUPTIONS	1,920,554
2005 TOTALS	30 INTERRUPTIONS	2,718,855
2004 TOTALS	14 INTERRUPTIONS	1,791,200

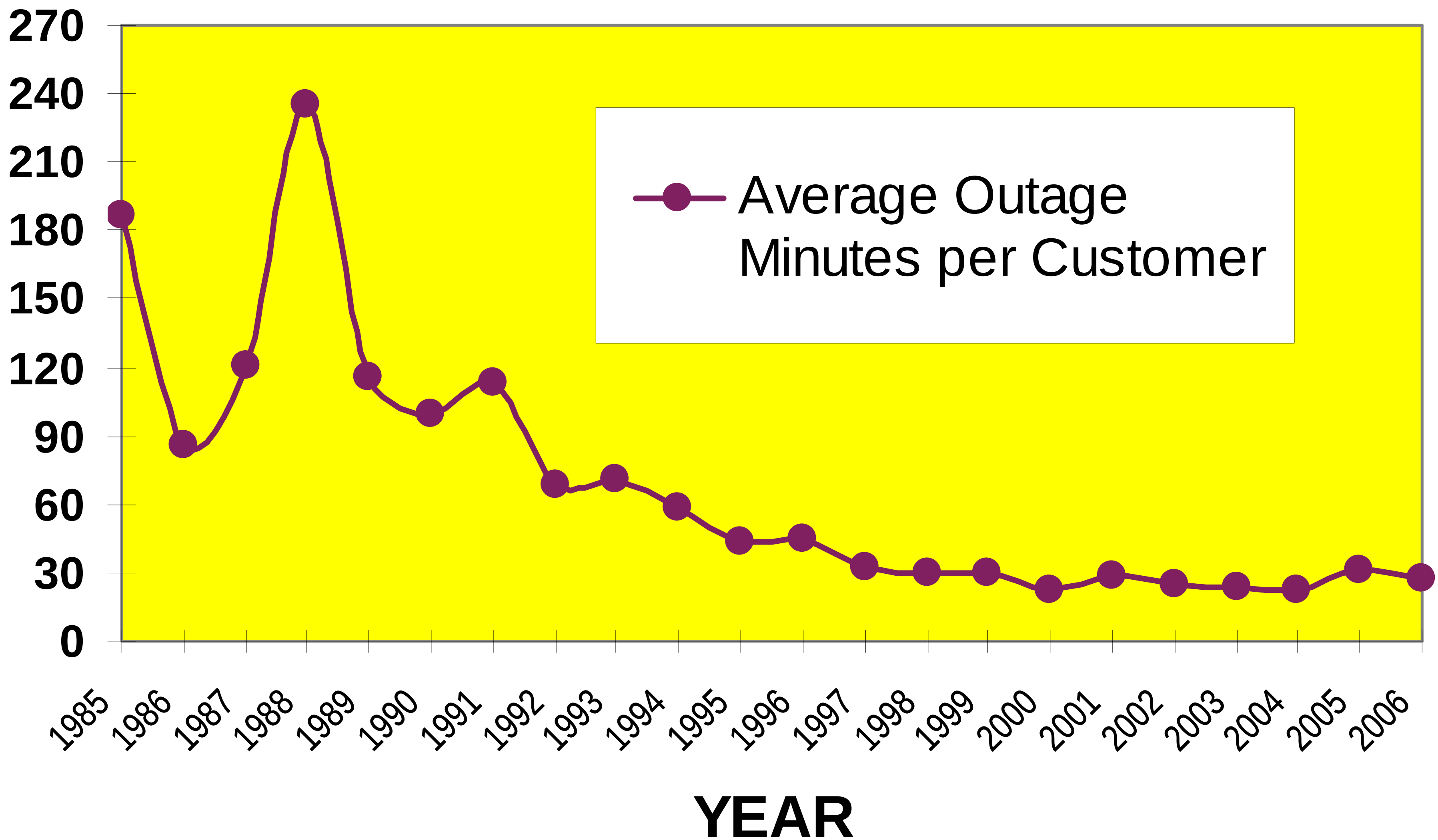
CUSTOMER MINUTES PER MONTH



2005 SAIDI - CEA URBAN UTILITES



"WORLD CLASS RESULTS"



Load Duration Curves

2006

enersource
Corporation

4.16/13.8/27.6/44 kV System

System Planning Department

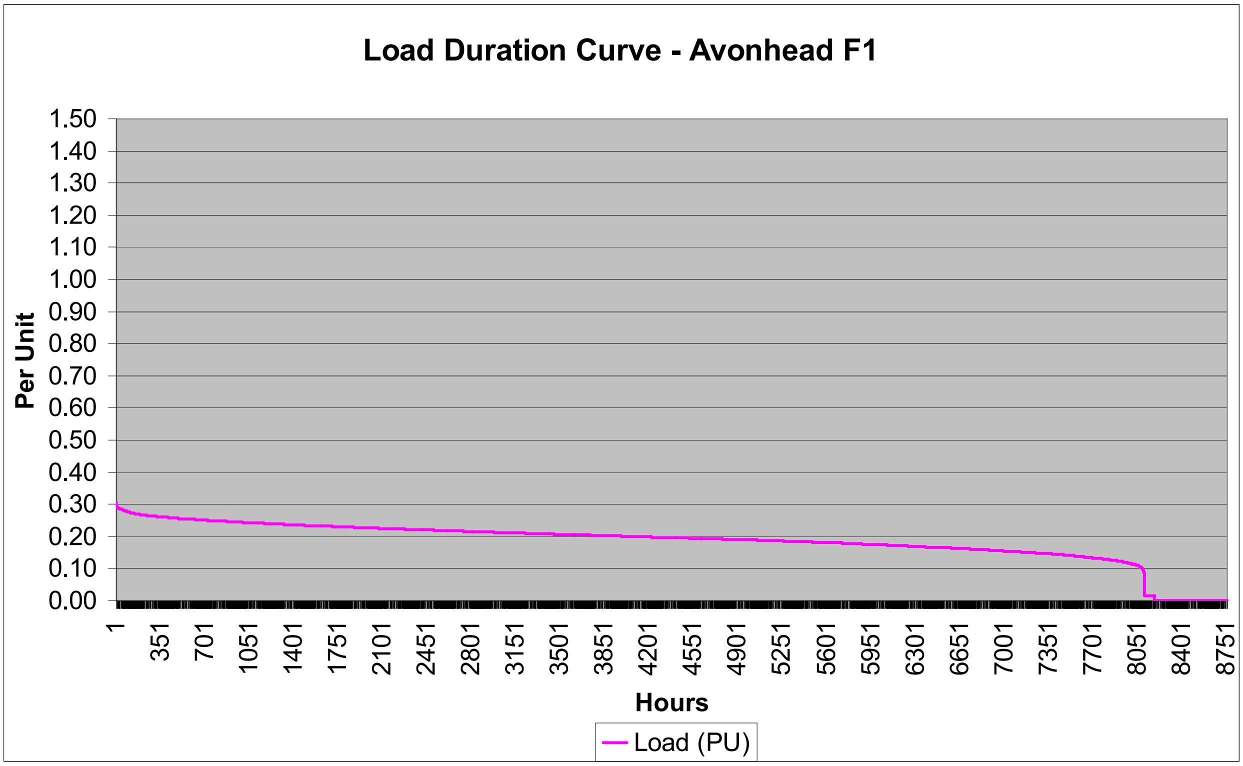
Enersource Hydro Mississauga

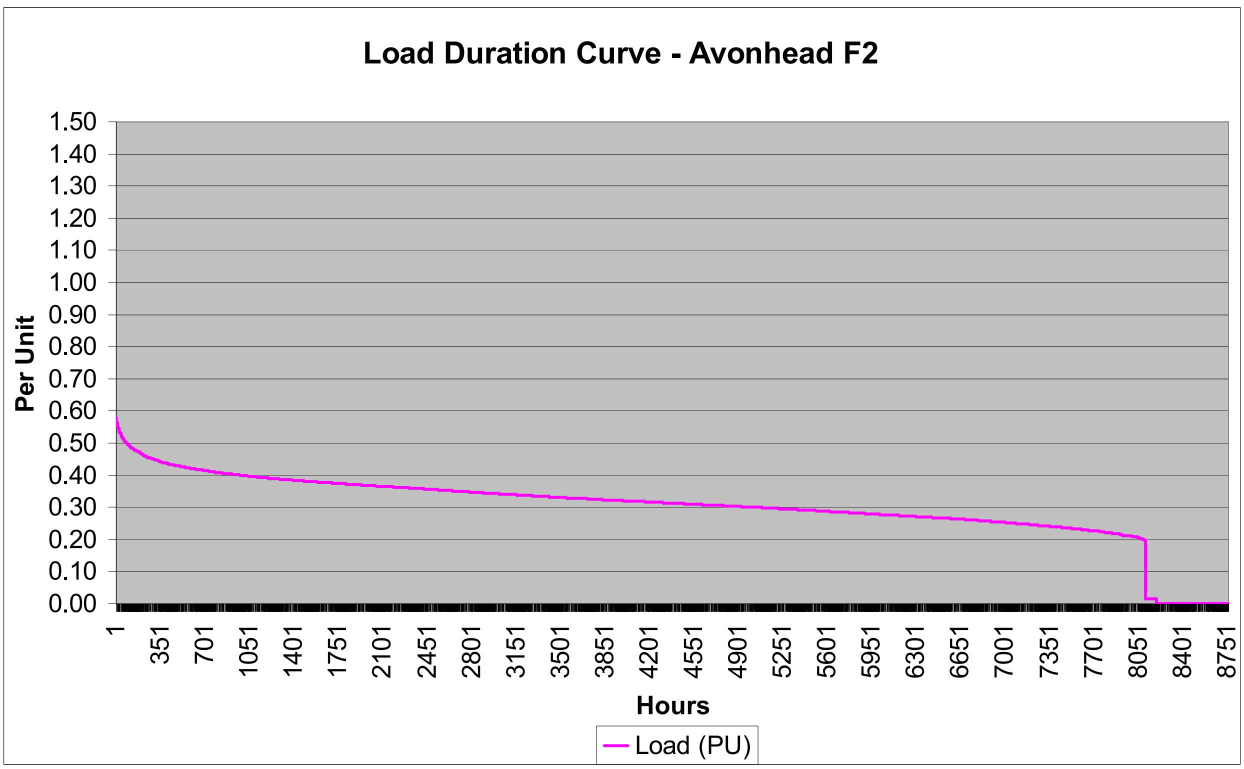
August 2006

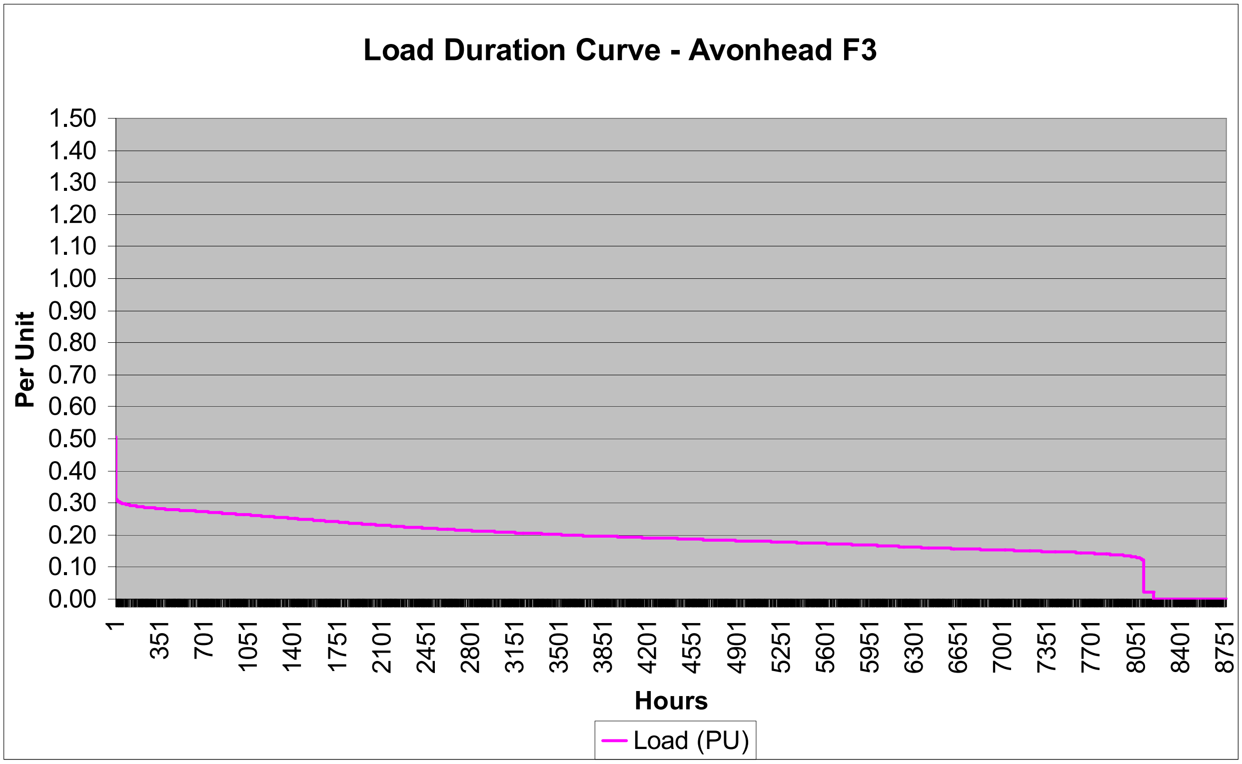
Table of Contents

27.6 kV South System
4.16 kV Substations

Avonhead MS






Load Duration Curve - Avonhead F3
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0.70
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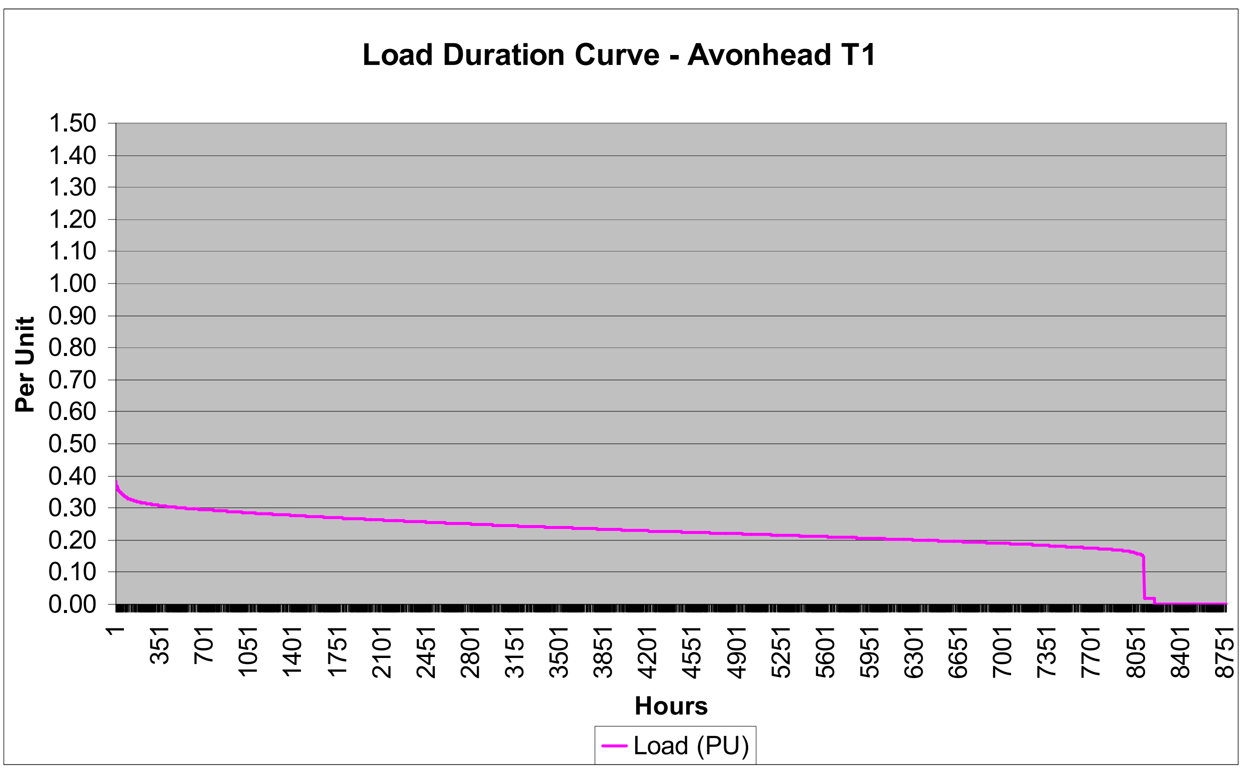
8401
8751
Hours
Load (PU)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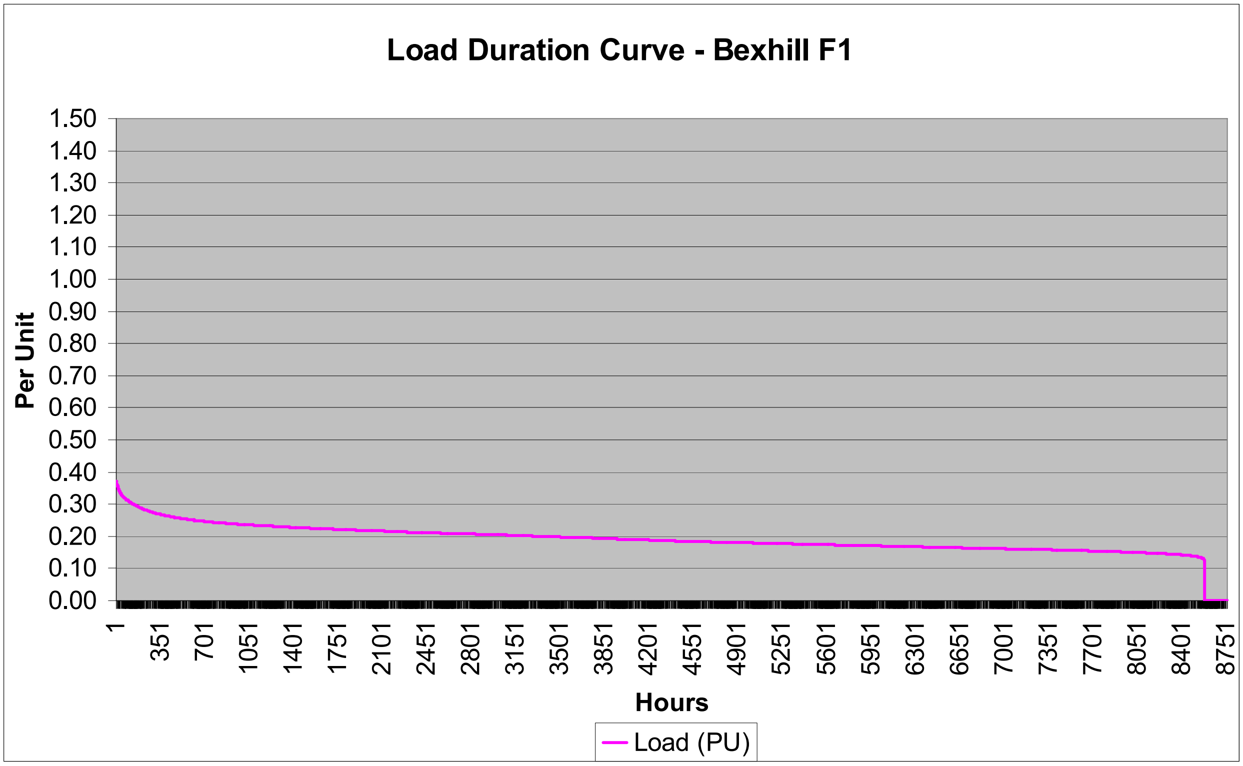
8751
Hours
Load (PU)

Bexhill MS



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0.00
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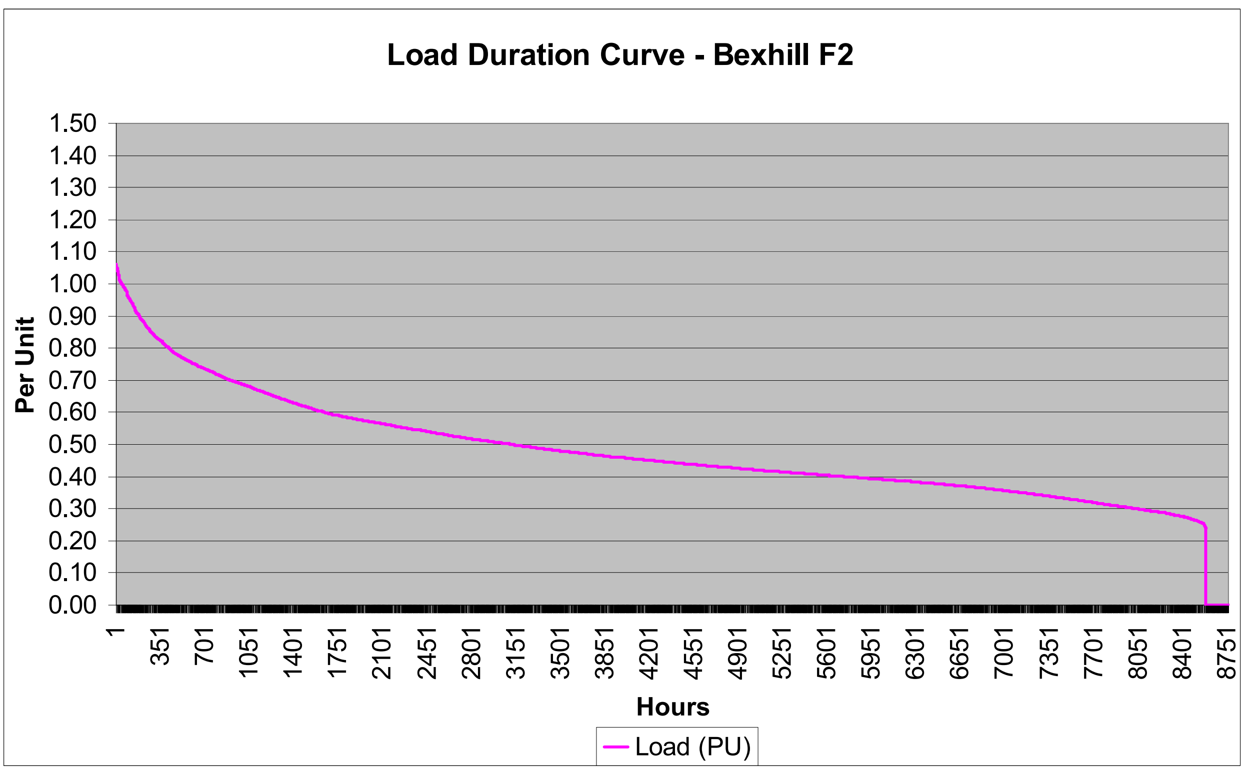
8401
8751
Hours
Load (PU)



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0.90
0.80
0.70
0.60
0.50
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Per Unit
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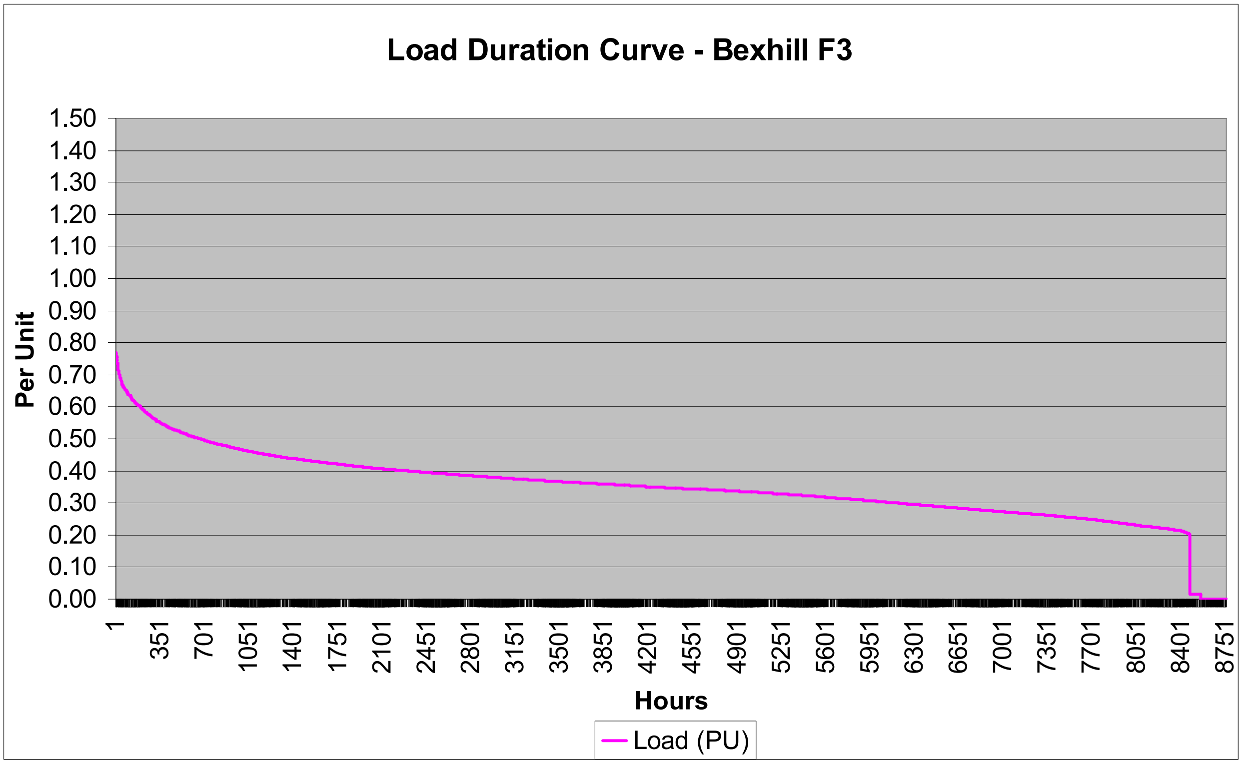
8401
8751
Hours
Load (PU)



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1.00
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0.80
0.70
0.60
0.50
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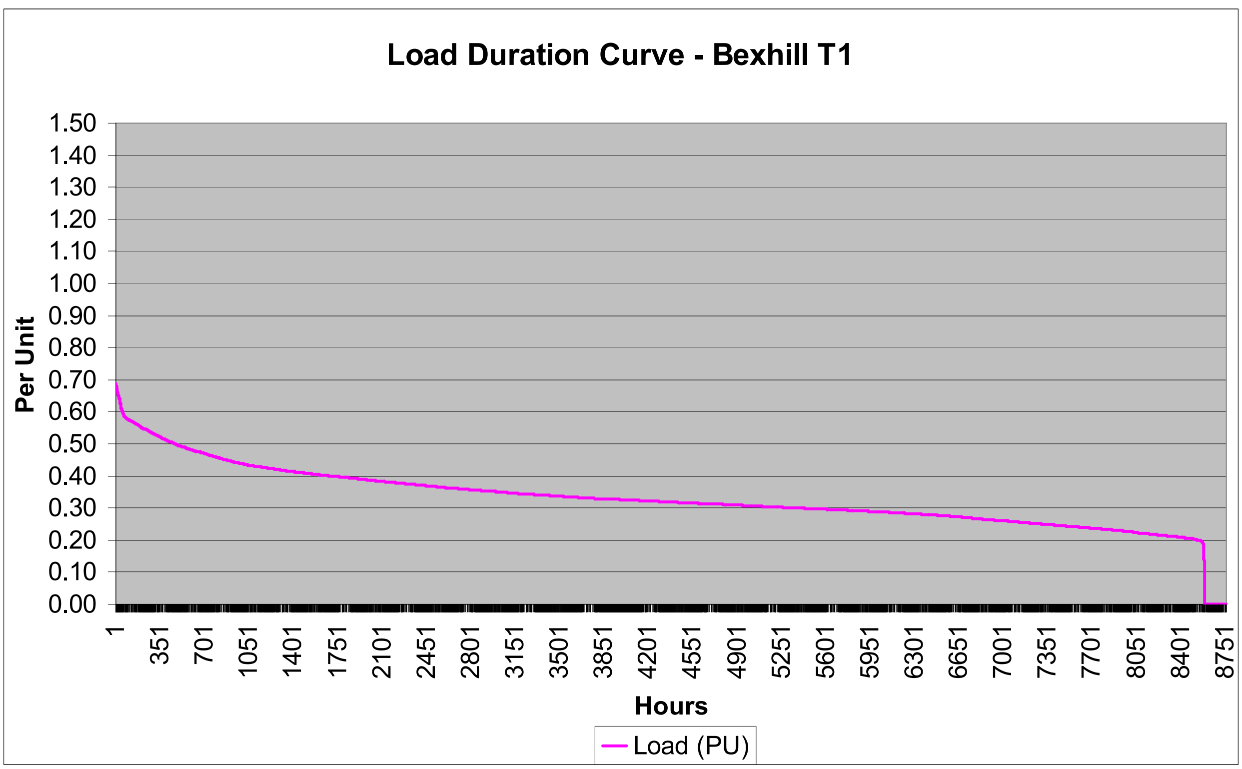
Hours
Load (PU)



Load Duration Curve - Bexhill T1
Per Unit
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1.20
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1.00
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8401
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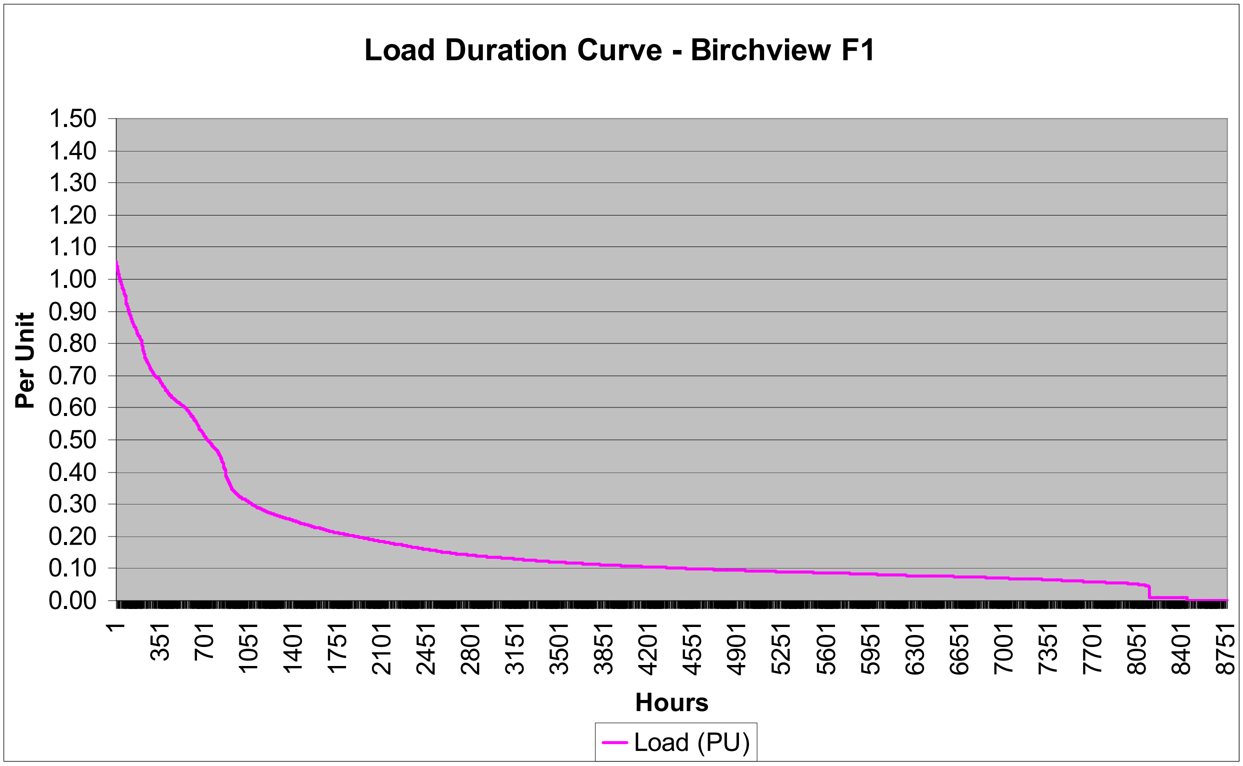
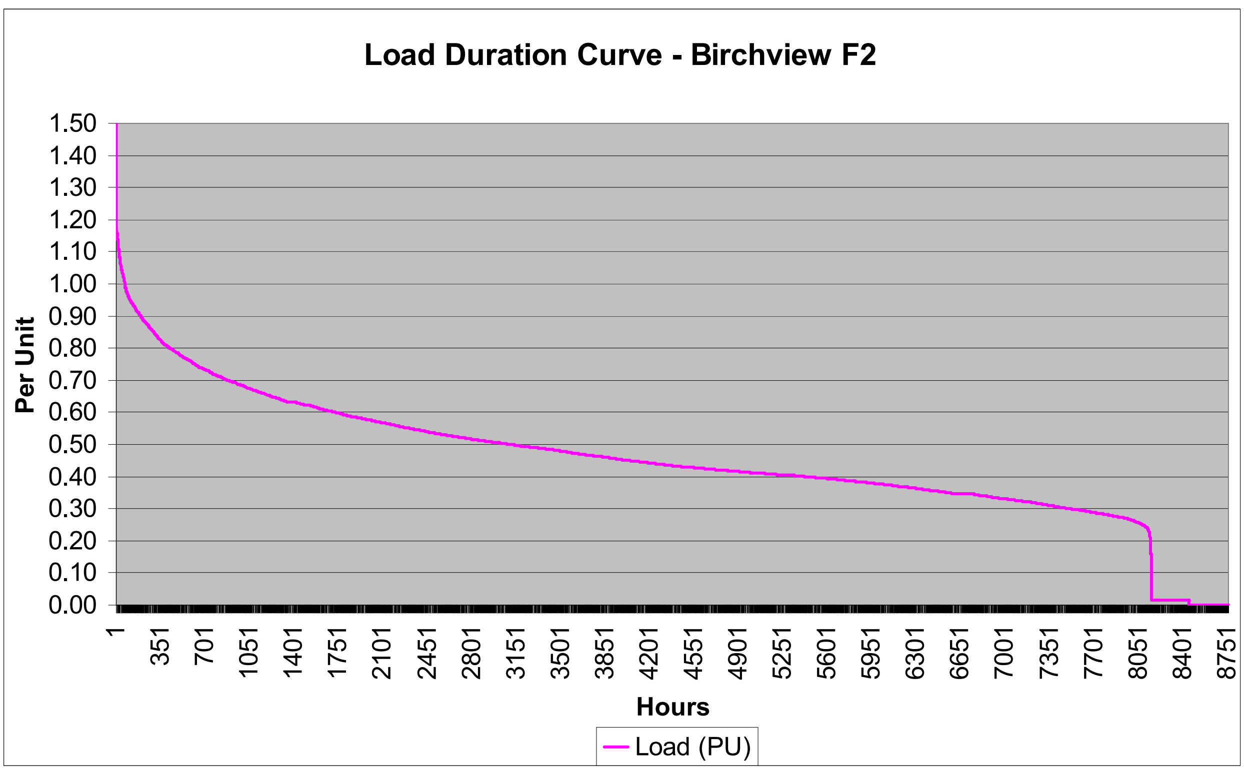
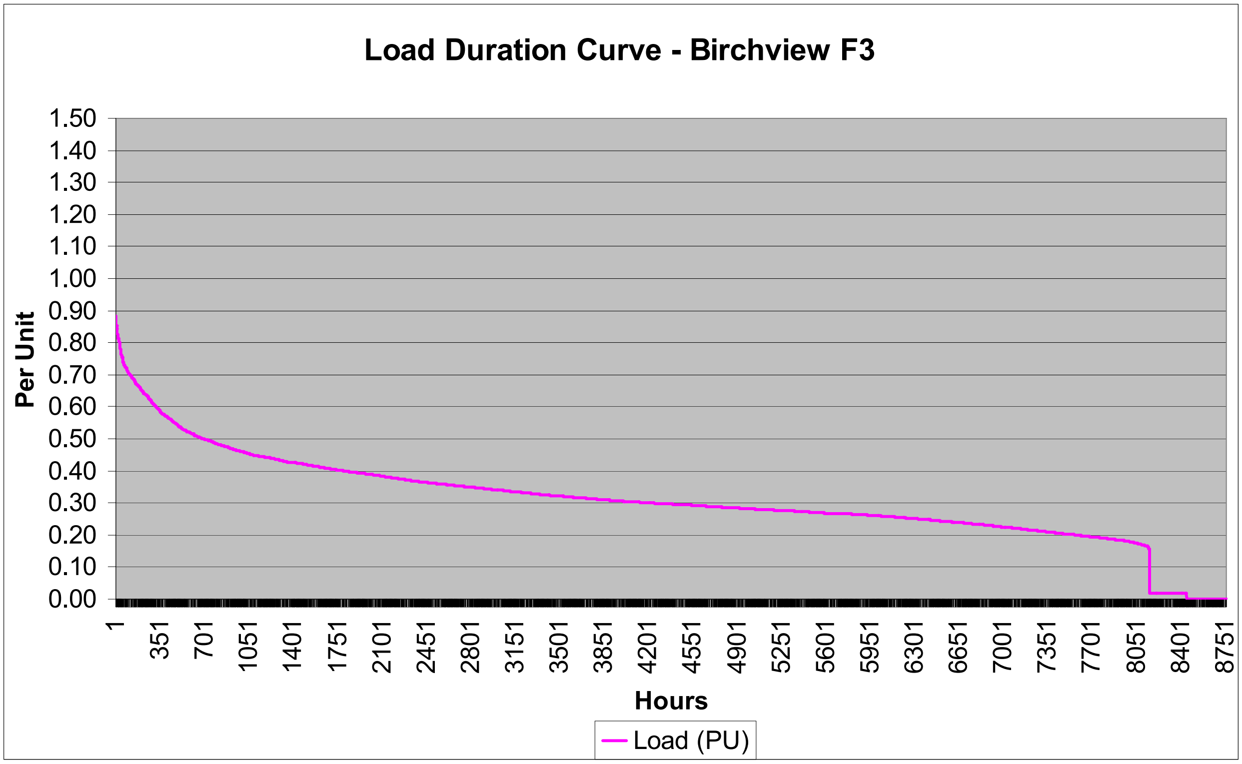
Hours
Load (PU)

Birchview MS






Load Duration Curve - Birchview F3
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1.40
1.30
1.20
1.10
1.00
0.90
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0.70
0.60
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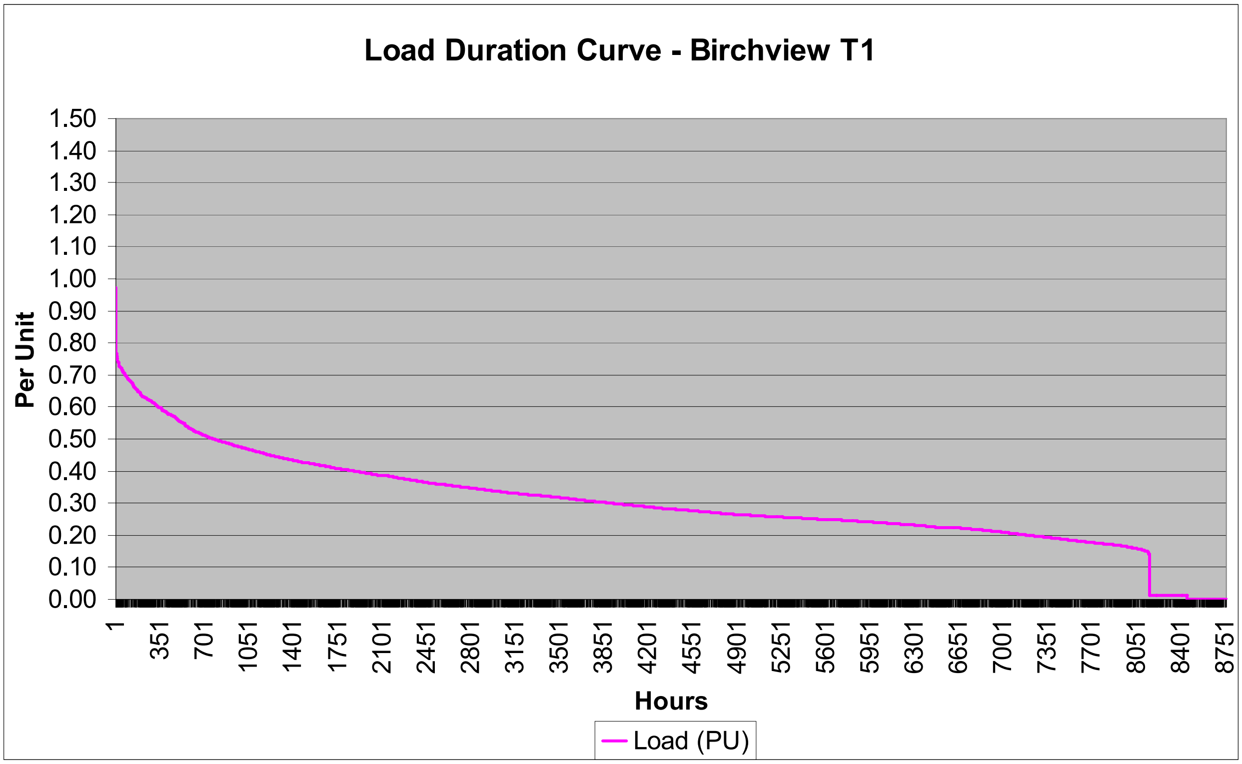
8751
Hours
Load (PU)


Load Duration Curve - Birchview T1
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
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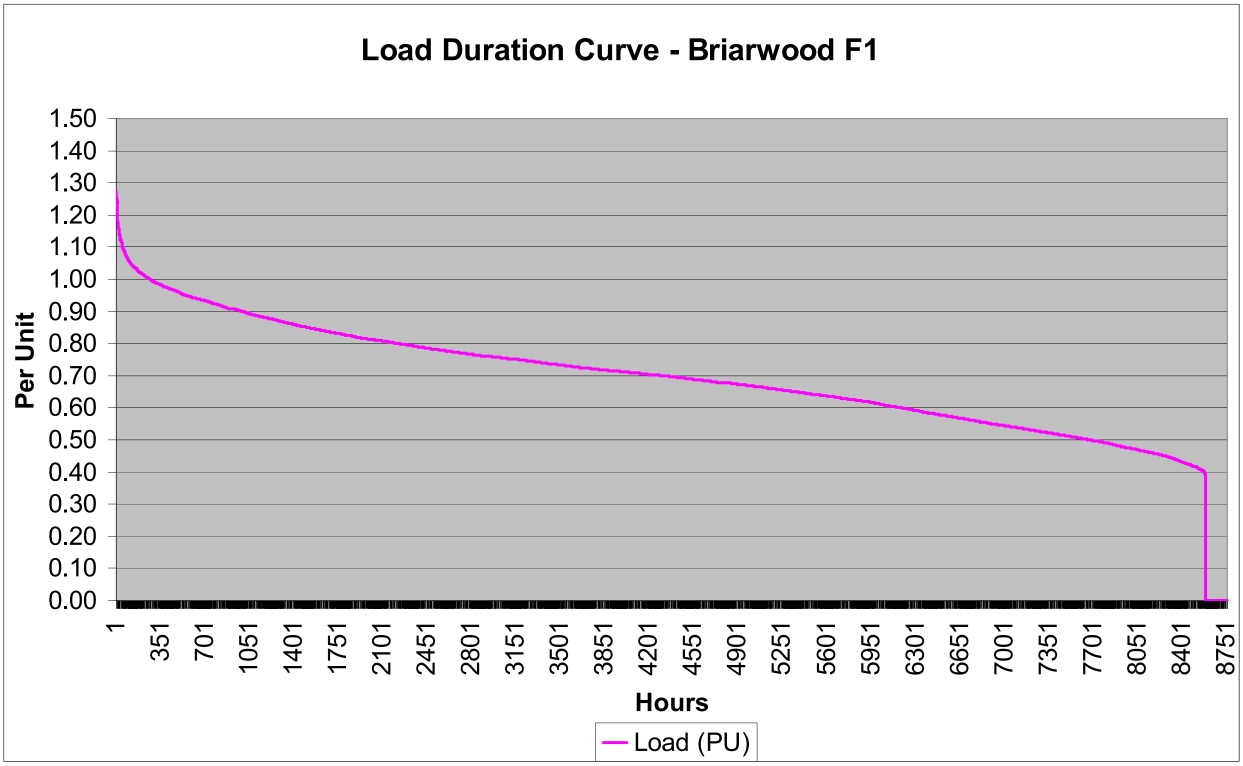
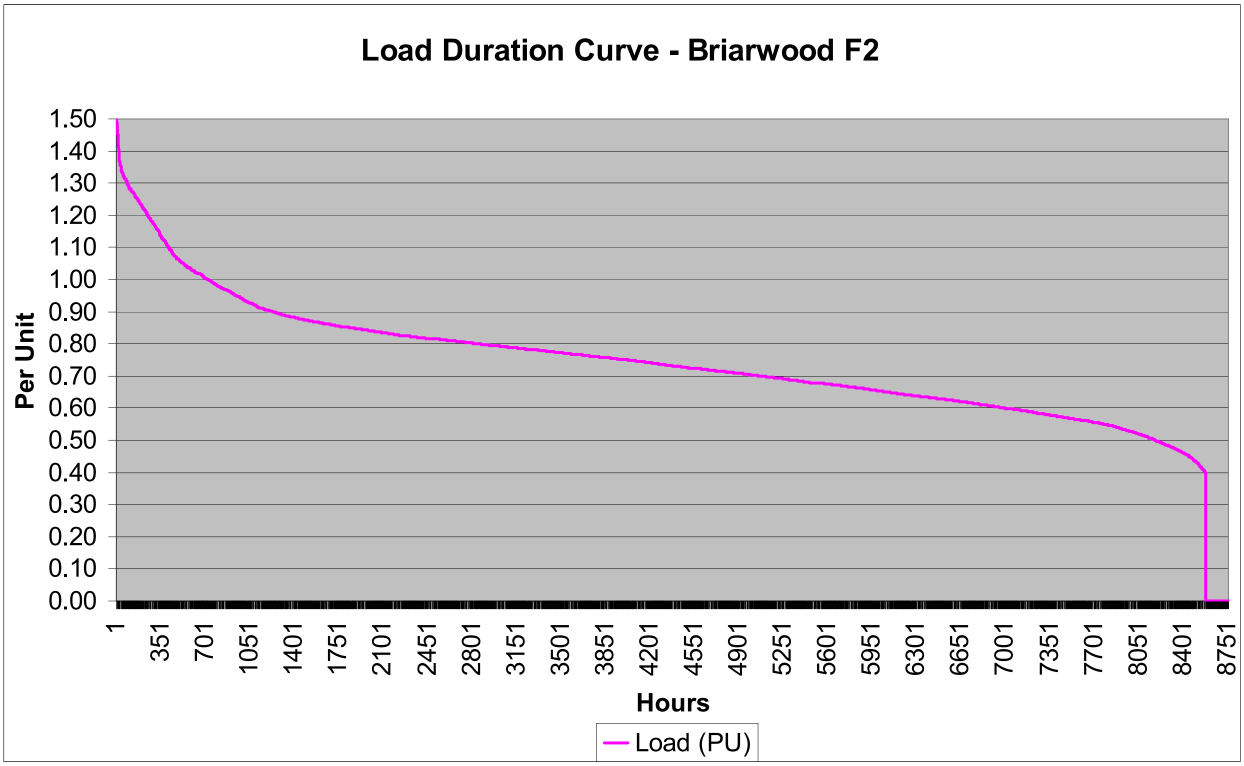
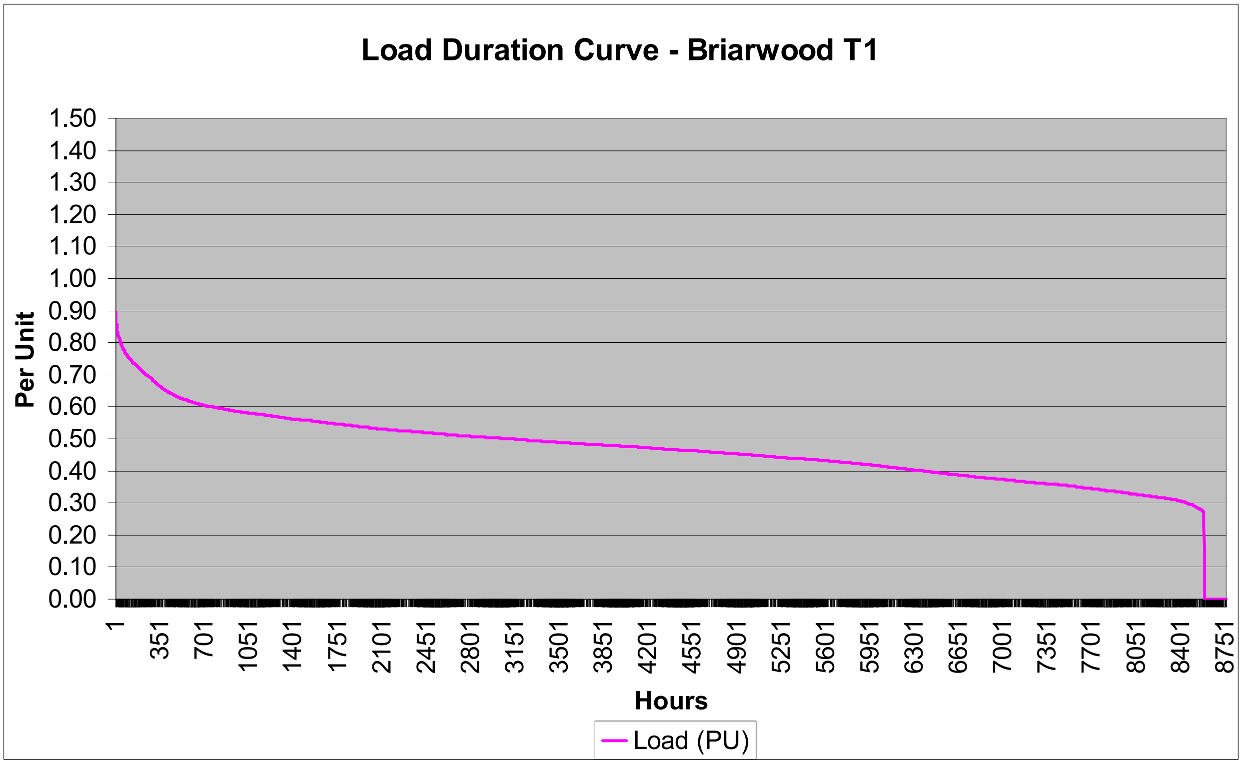
8401
8751
Hours
Load (PU)

Briarwood MS



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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
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Per Unit
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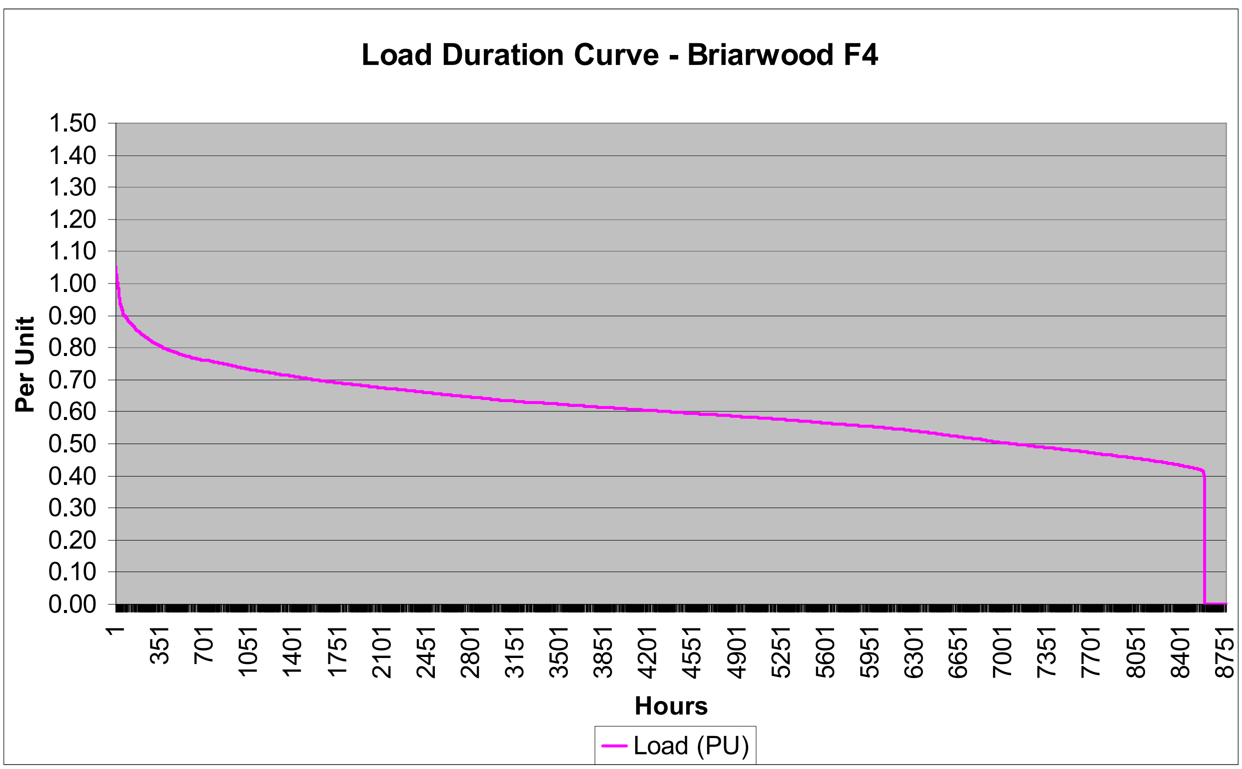
Hours
Load (PU)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Per Unit
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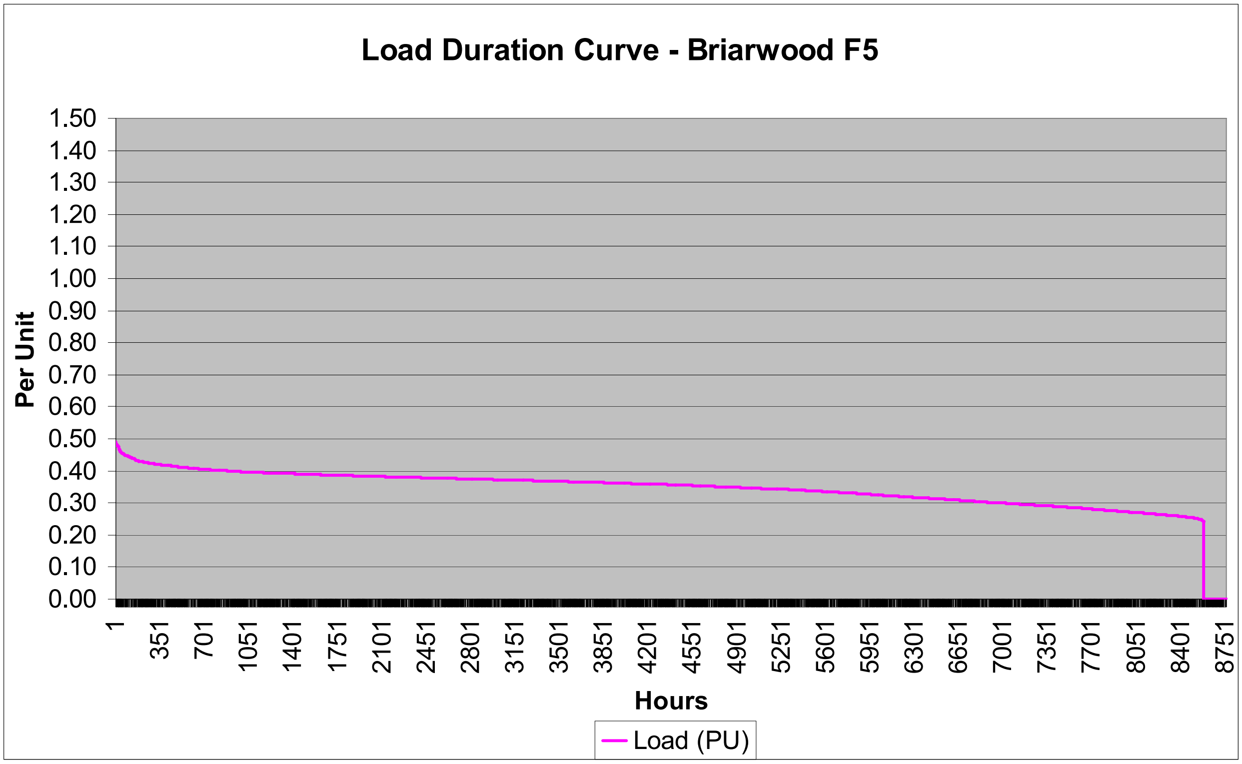
Hours
Load (PU)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Per Unit
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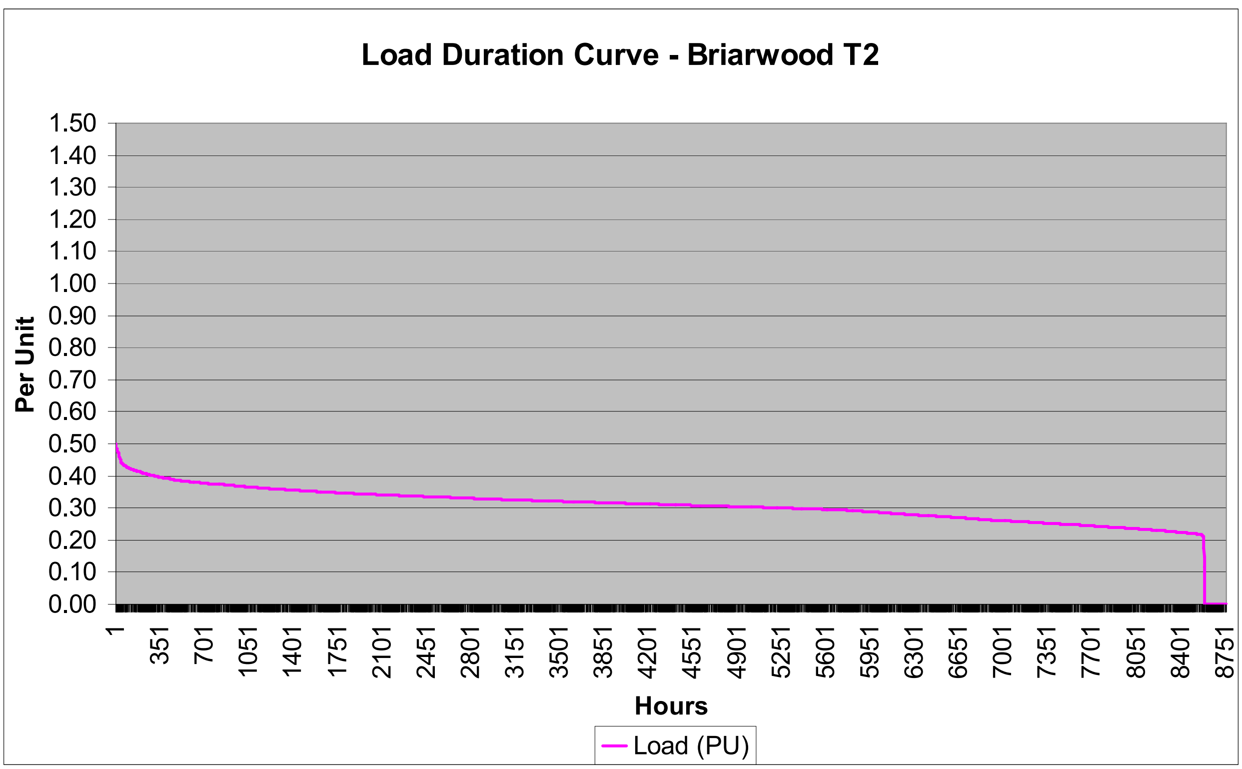
Hours
Load (PU)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Per Unit
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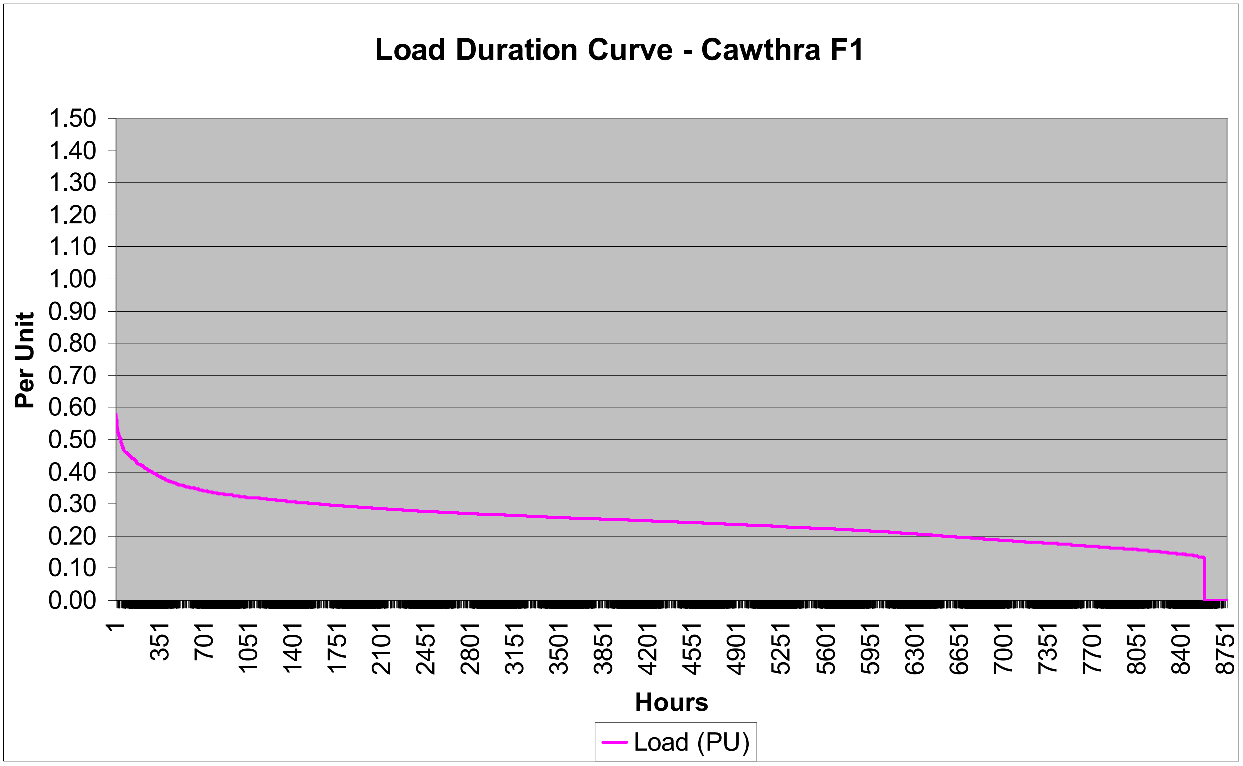
Hours
Load (PU)

Cawthra MS



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0.20
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Per Unit
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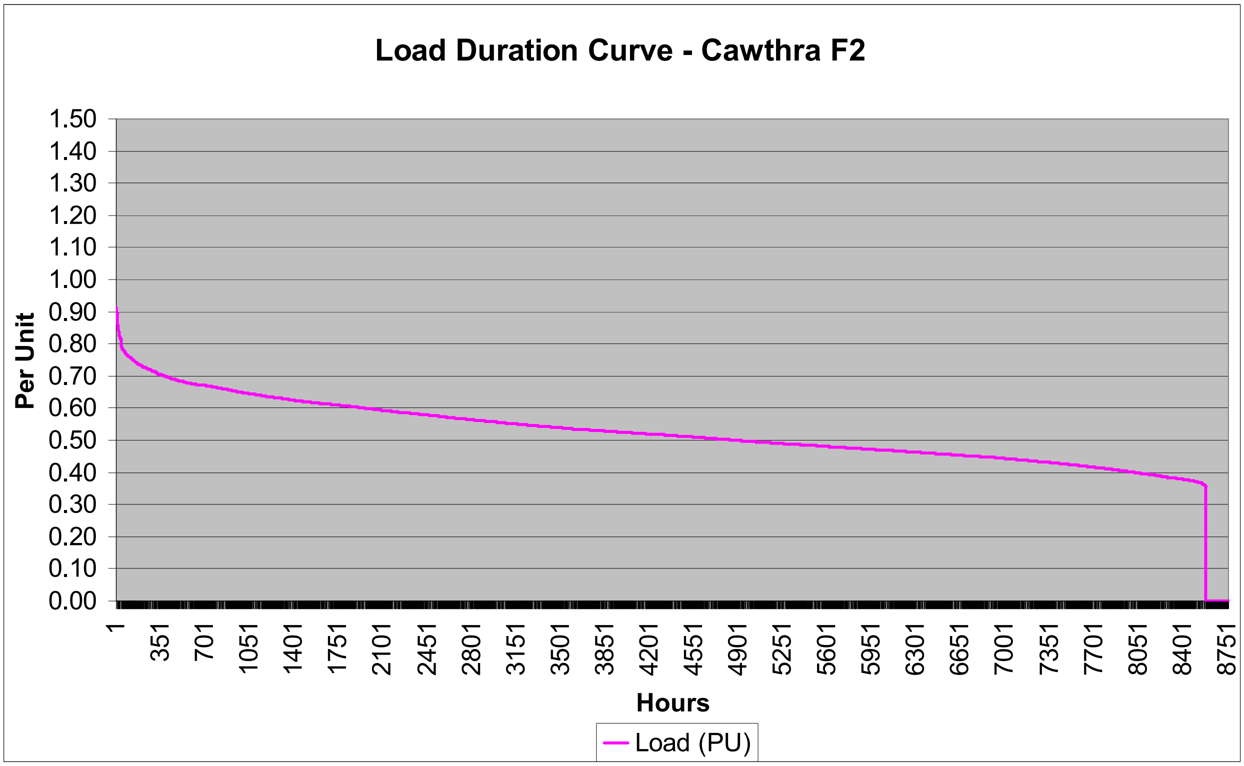
8751
Hours
Load (PU)



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0.70
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0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
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1051
1401
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2101
2451
2801
3151
3501
3851
4201
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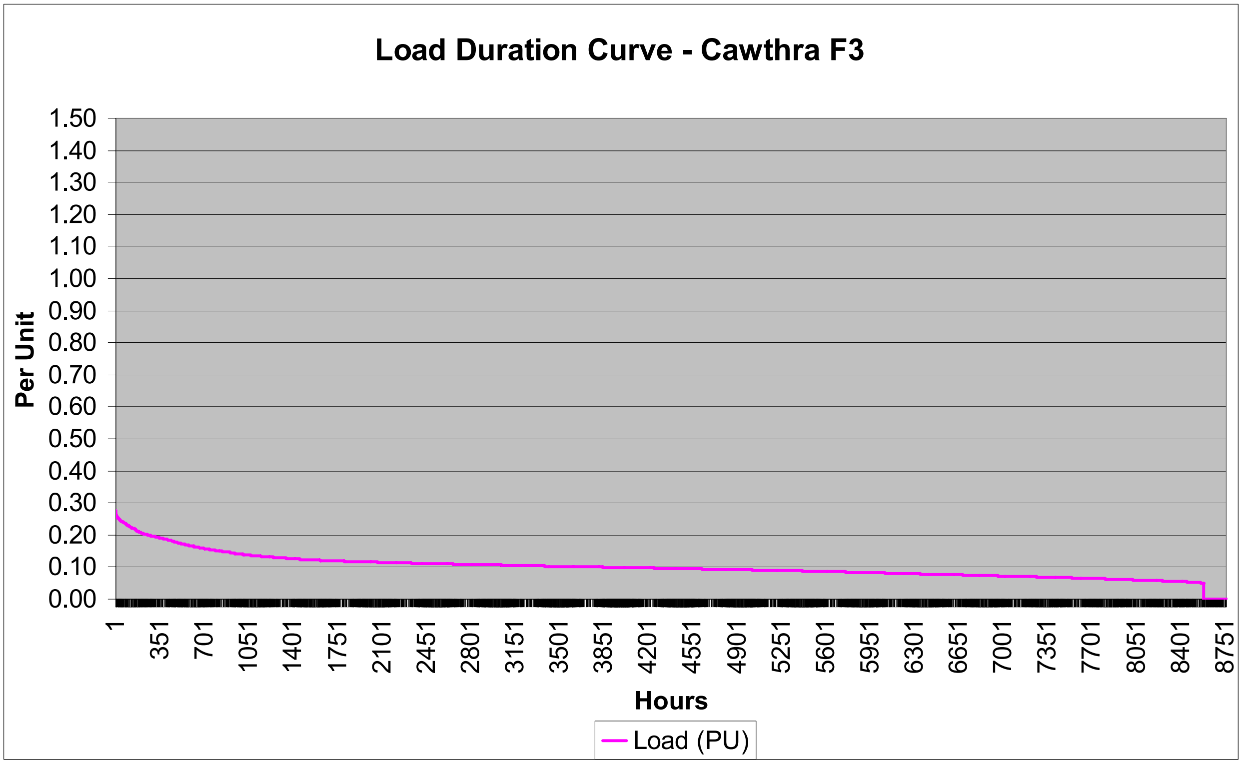
8751
Hours
Load (PU)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0.40
0.30
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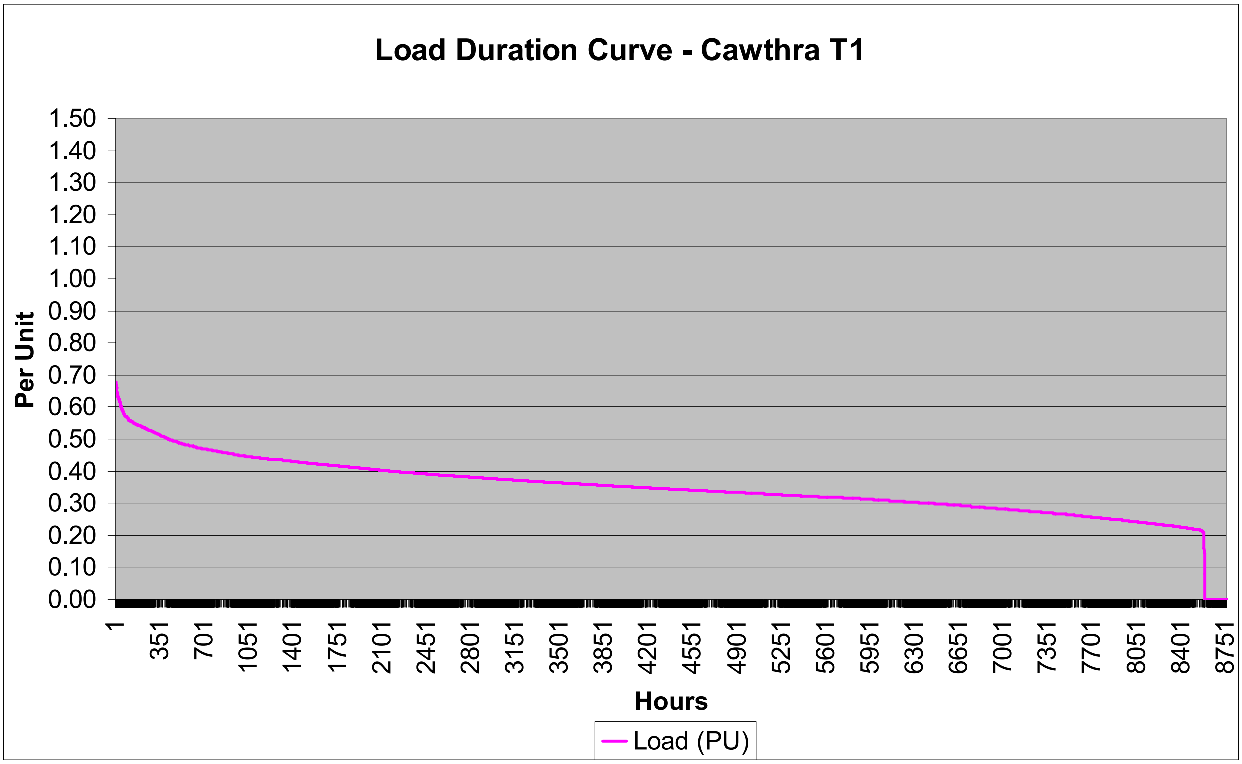
Hours
Load (PU)


Load Duration Curve - Cawthra T1
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0.70
0.60
0.50
0.40
0.30
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0.10
0.00
1
351
701
1051
1401
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2101
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4201
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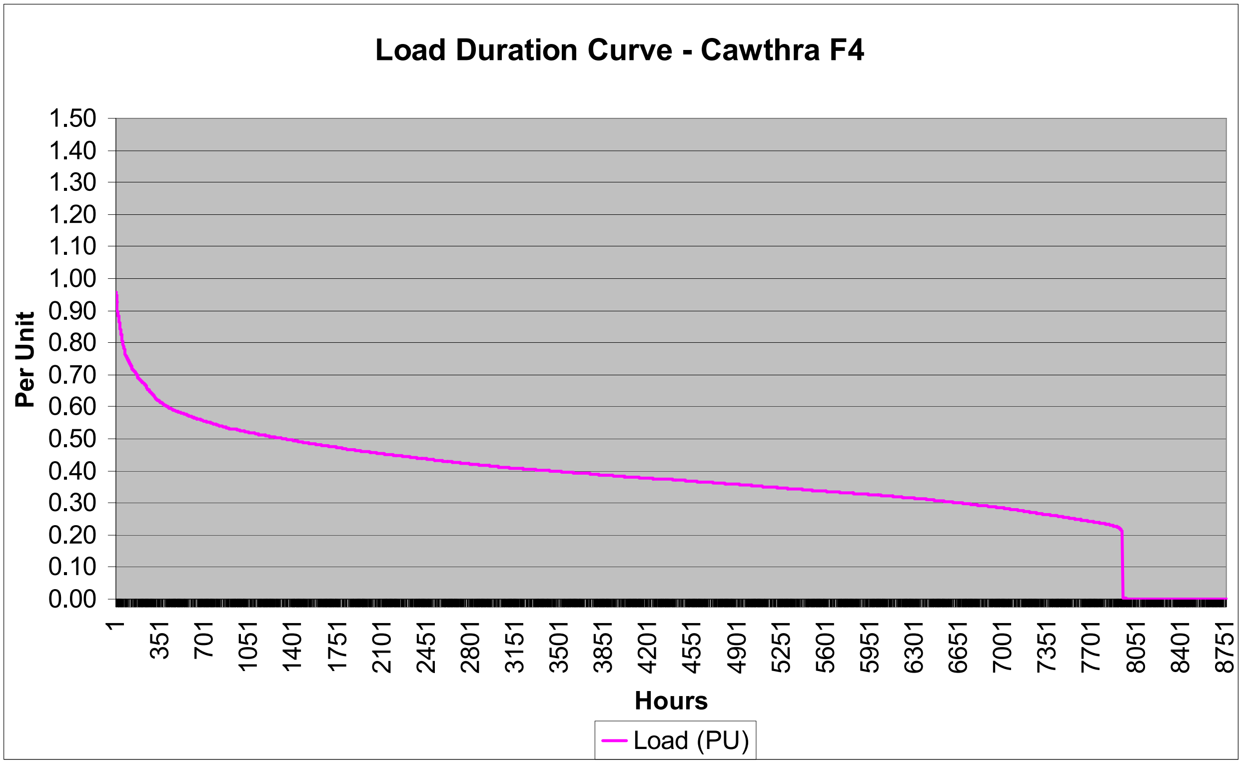
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cawthra F4
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
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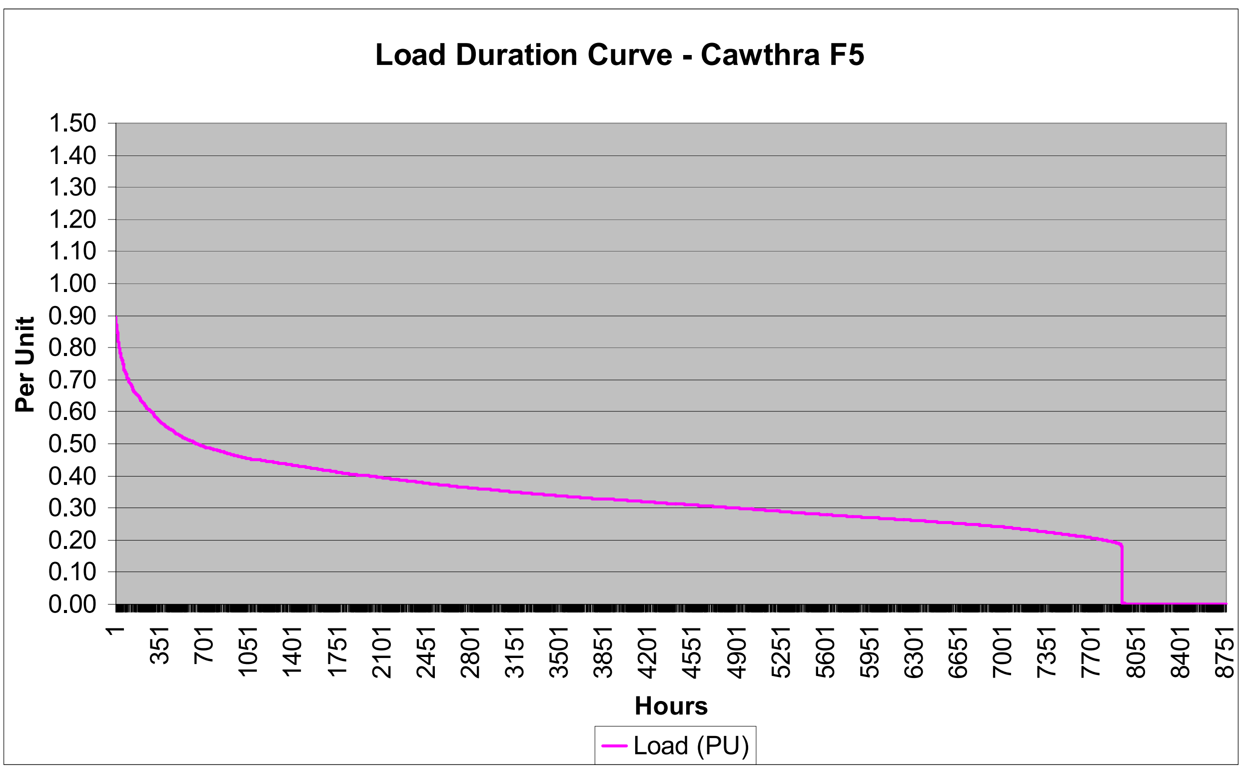
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cawthra F5
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
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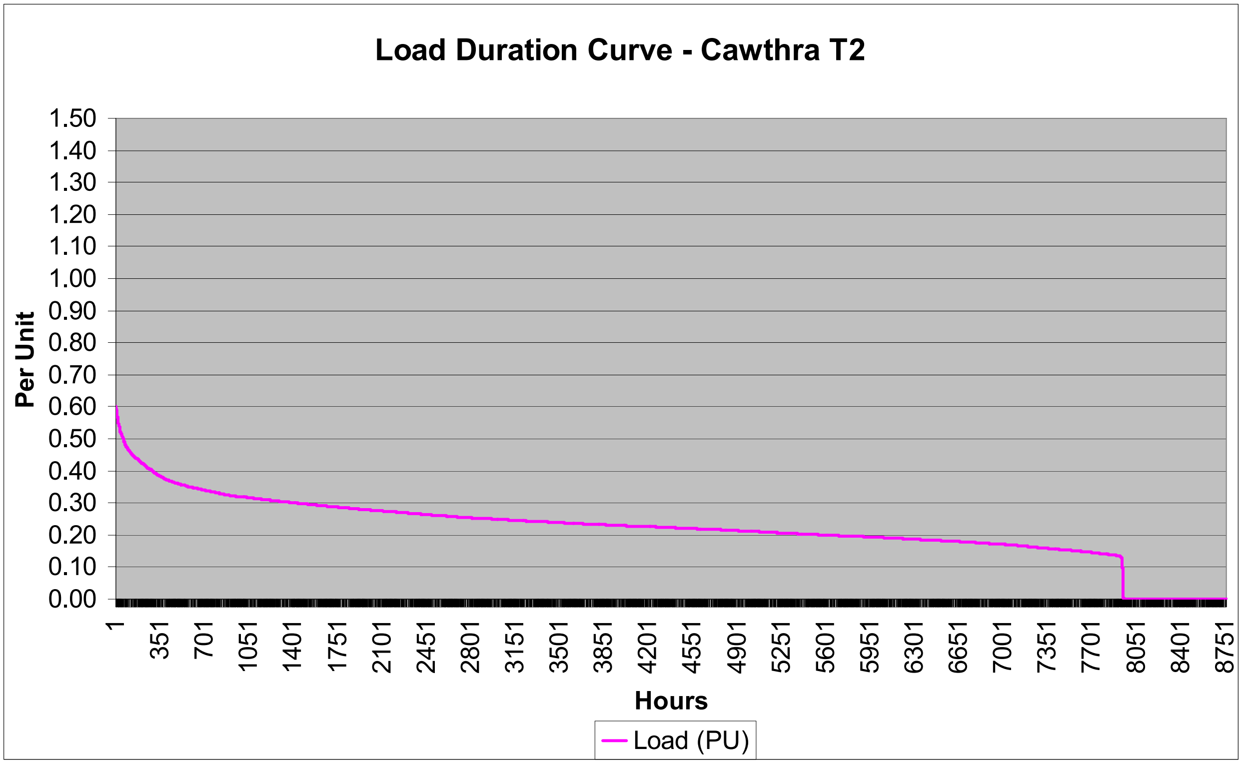
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cawthra T2
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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701
1051
1401
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2101
2451
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4201
4551
4901
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7351
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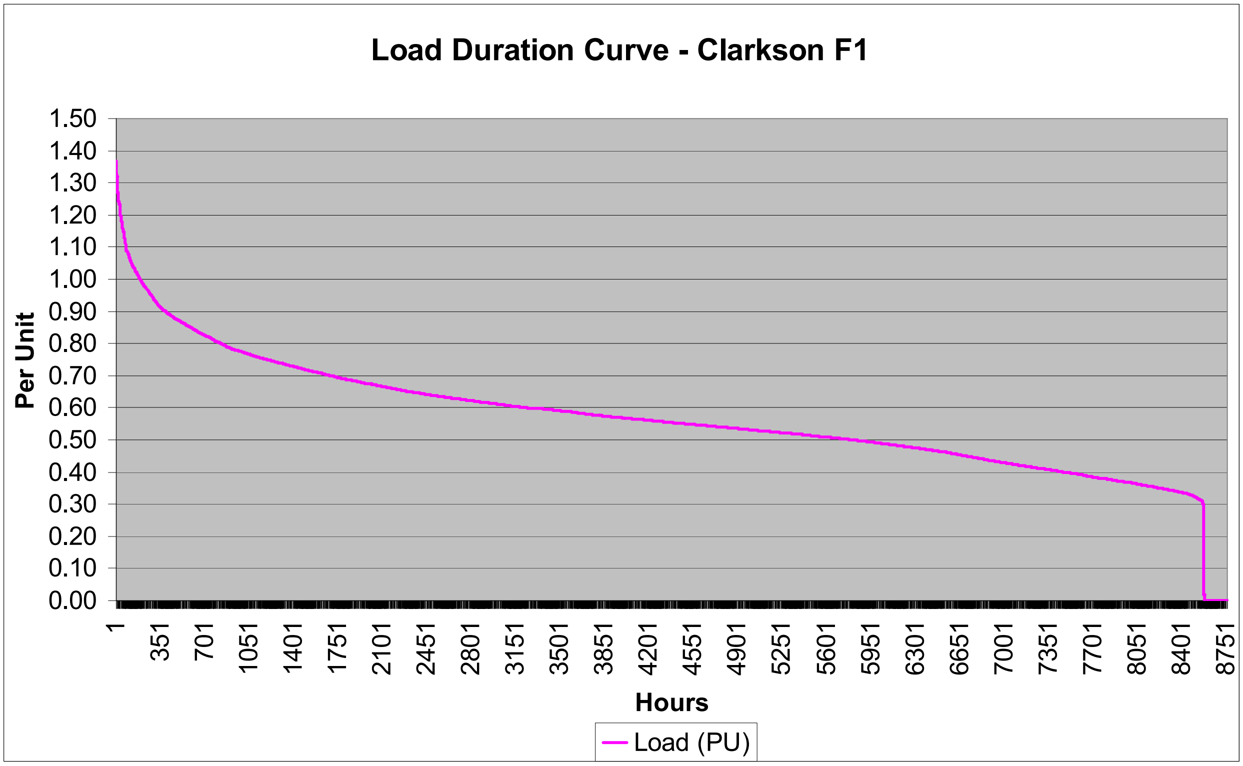
8401
8751
Hours
Load (PU)

Clarkson MS


Load Duration Curve - Clarkson F1
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
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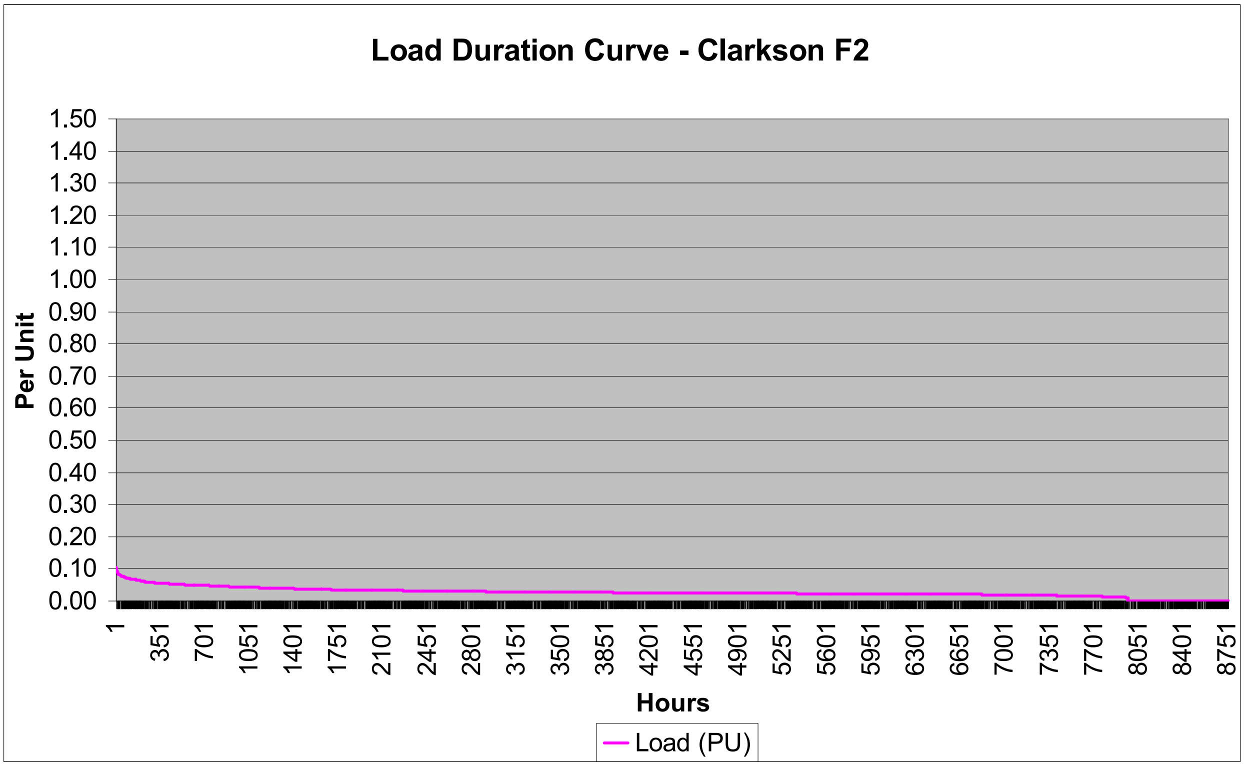
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Clarkson F2
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
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7351
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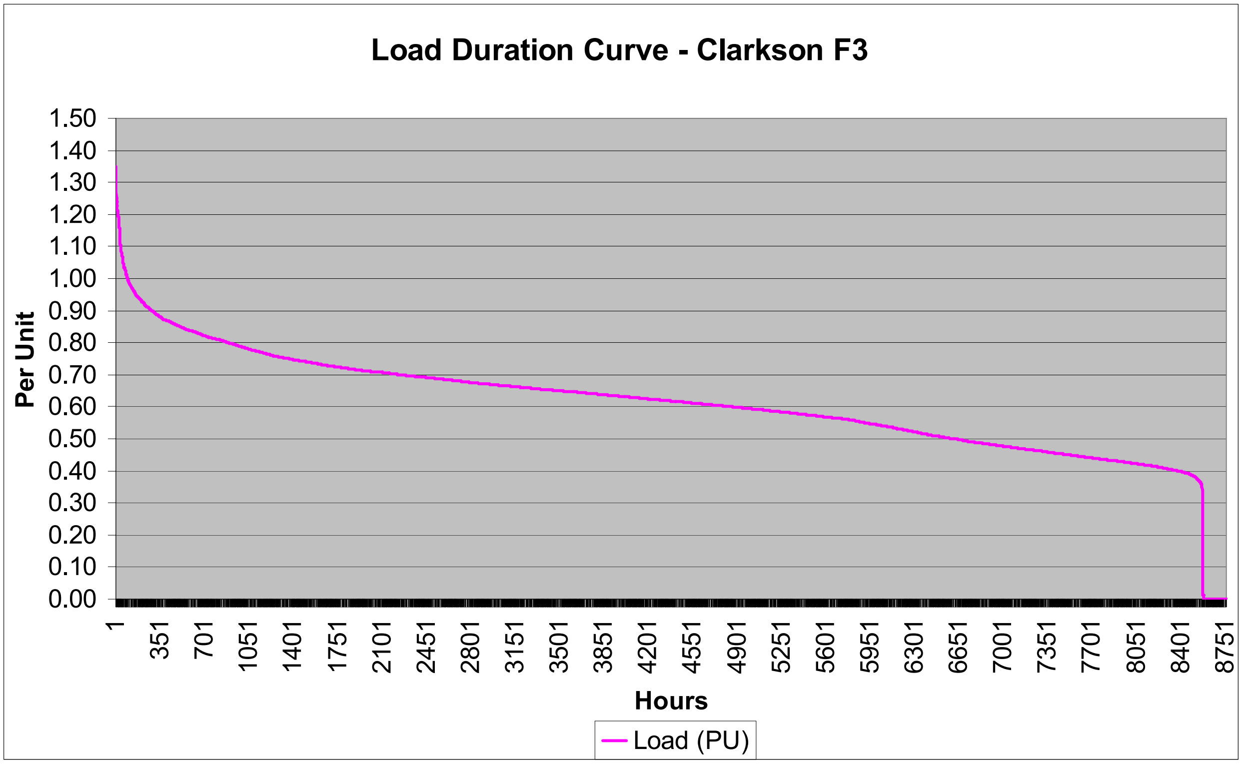
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Clarkson F3
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1.00
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6651
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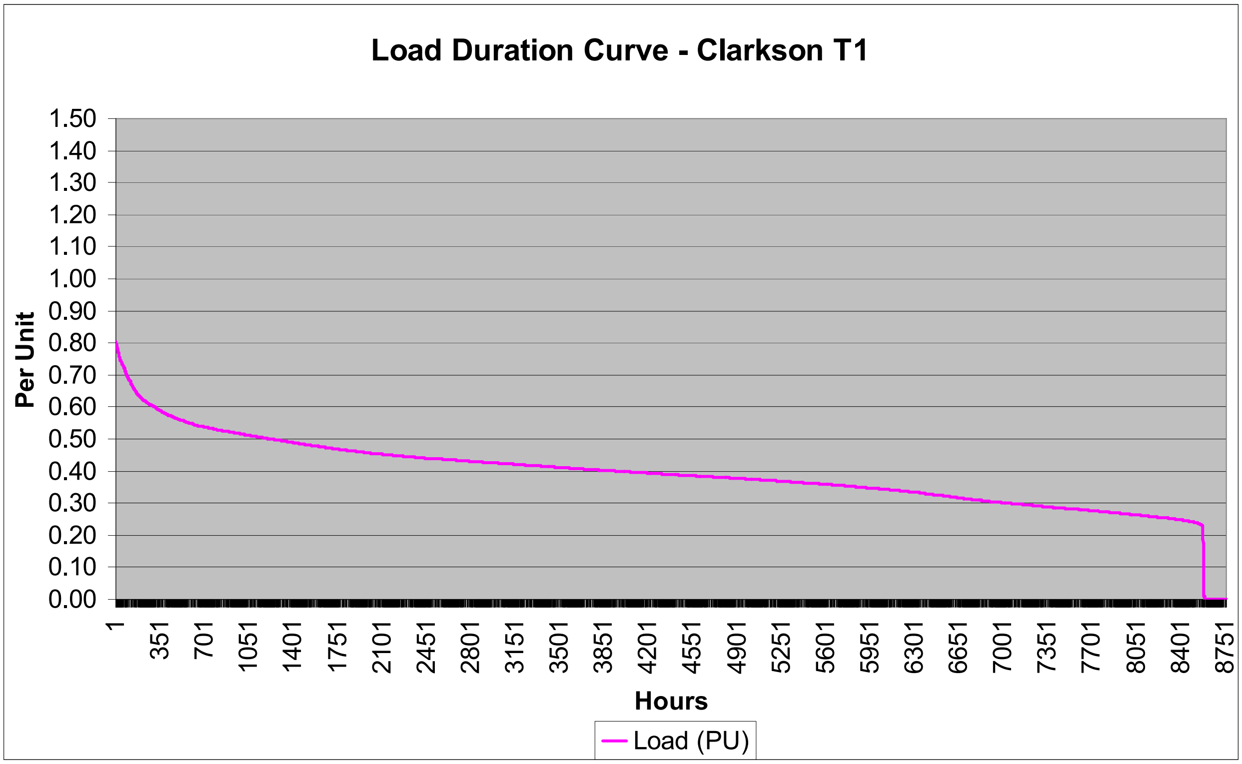
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Clarkson T1
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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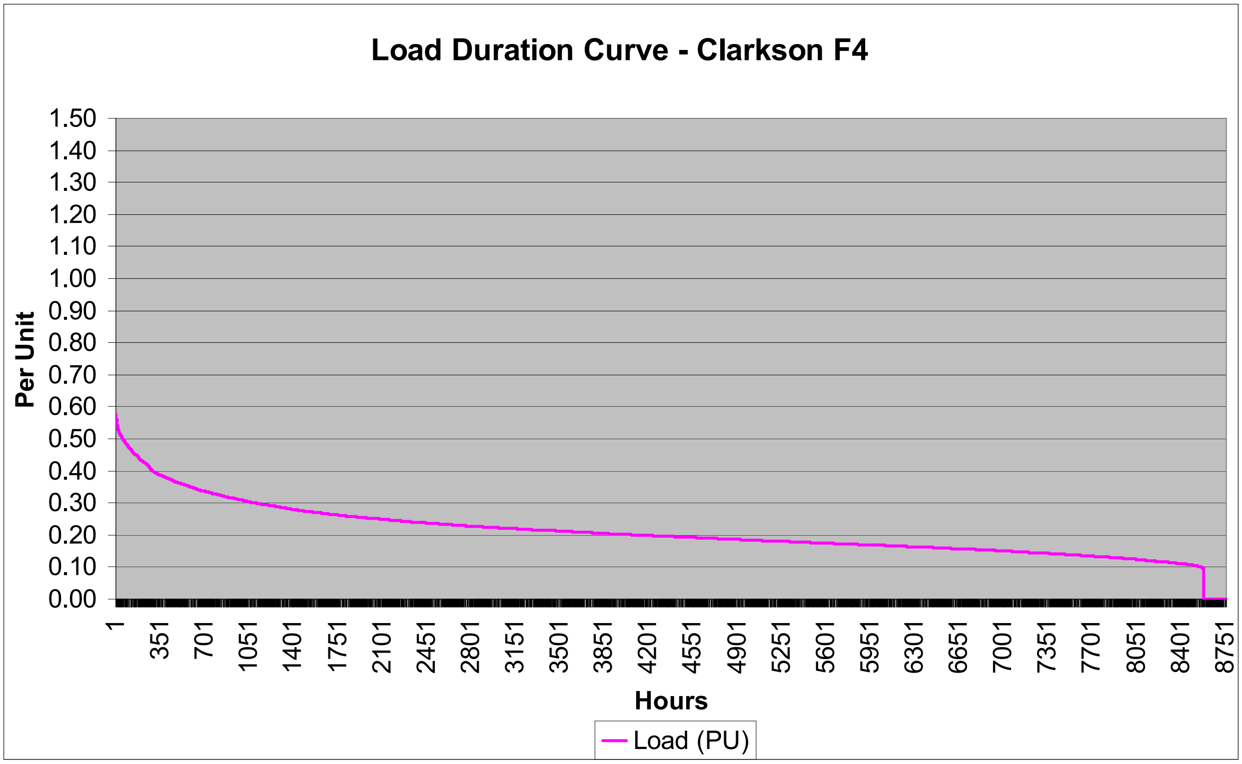
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Clarkson F4
Per Unit
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1.40
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
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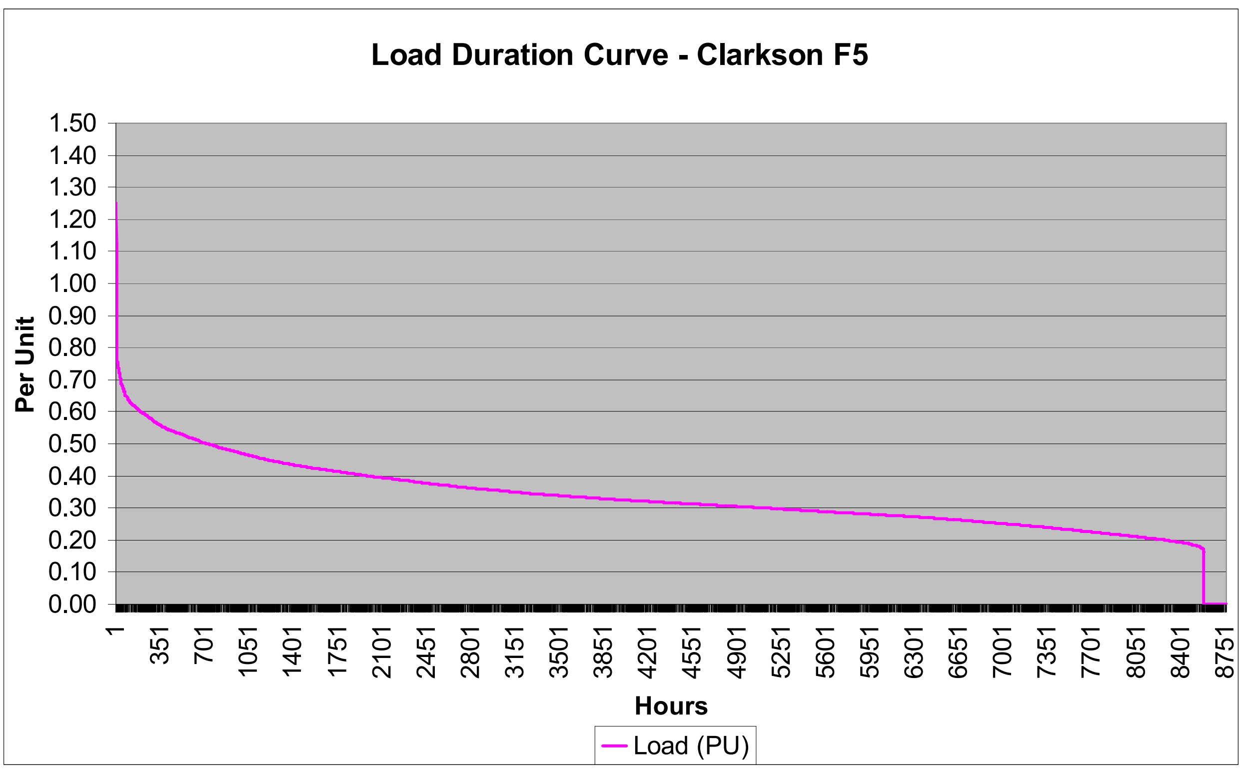
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Clarkson F5
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5951
6301
6651
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8051
8401
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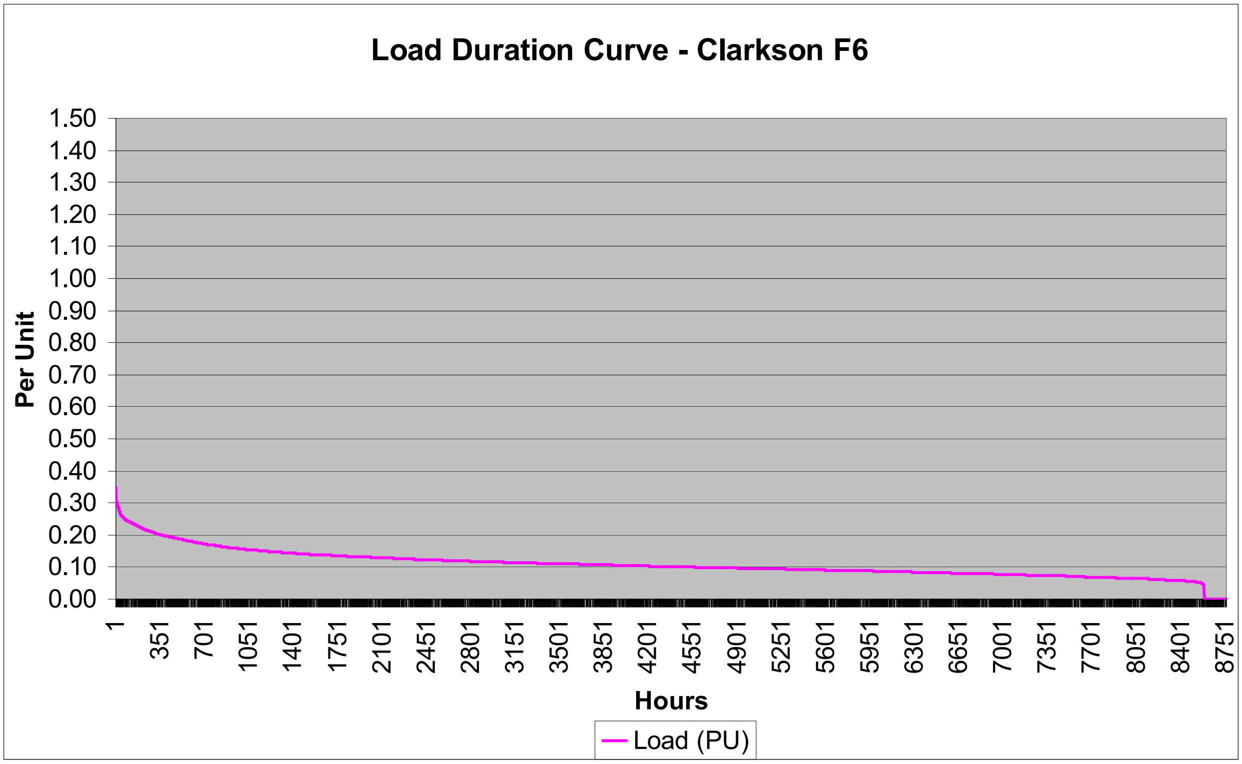
Hours
Load (PU)


Load Duration Curve - Clarkson F6
Per Unit
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0.60
0.50
0.40
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0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
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4201
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6651
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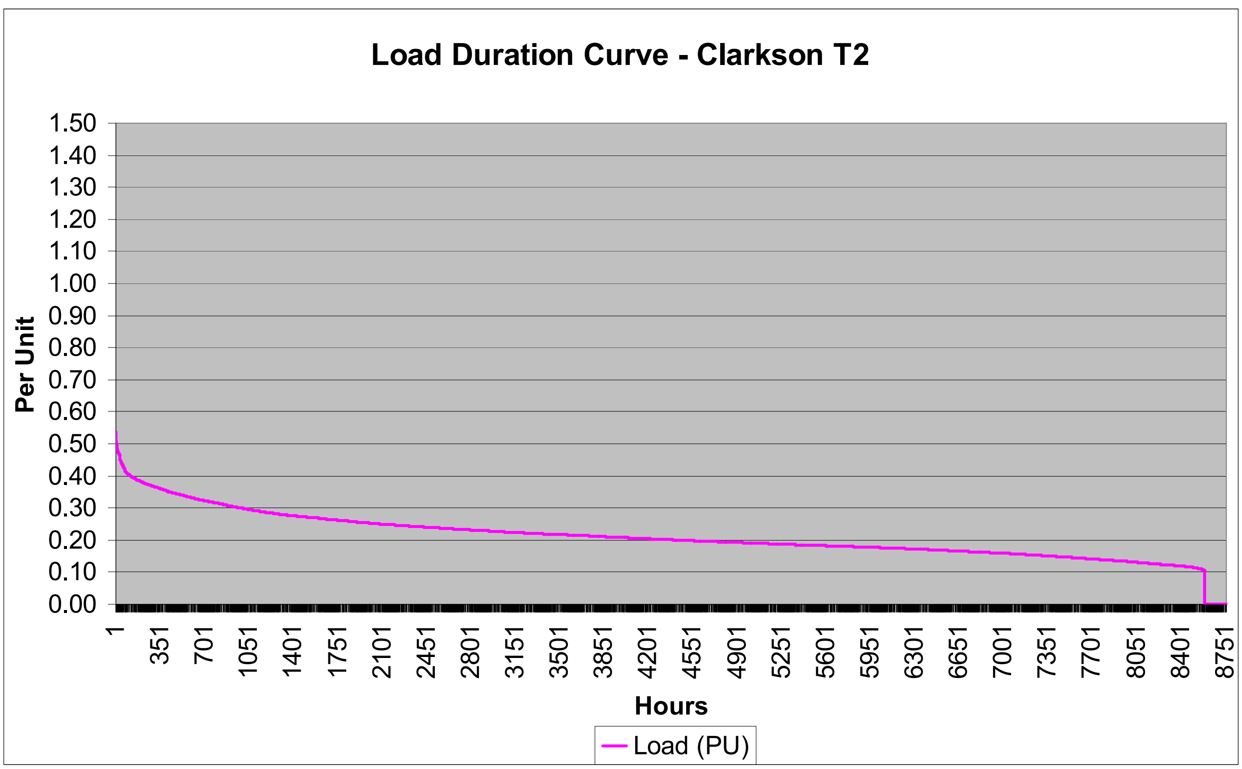
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Clarkson T2
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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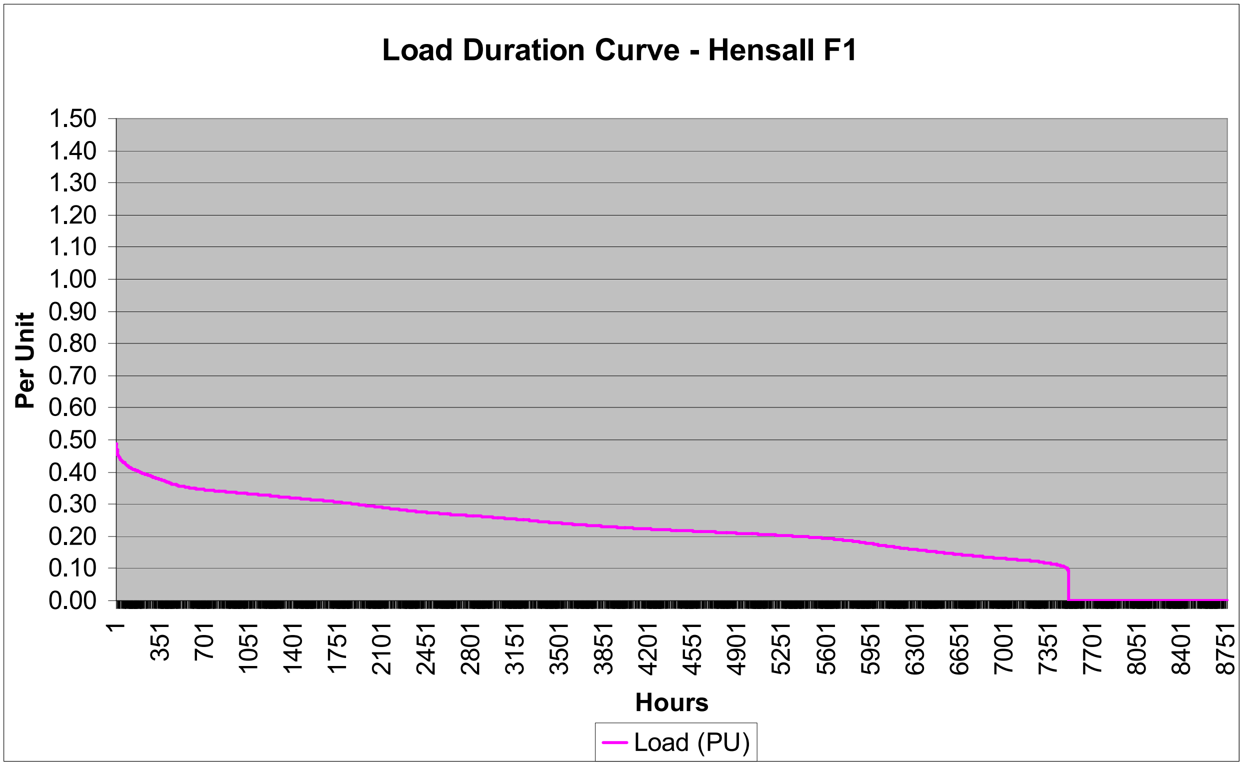
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Hensall MS


Load Duration Curve - Hensall F1
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
3501
3851
4201
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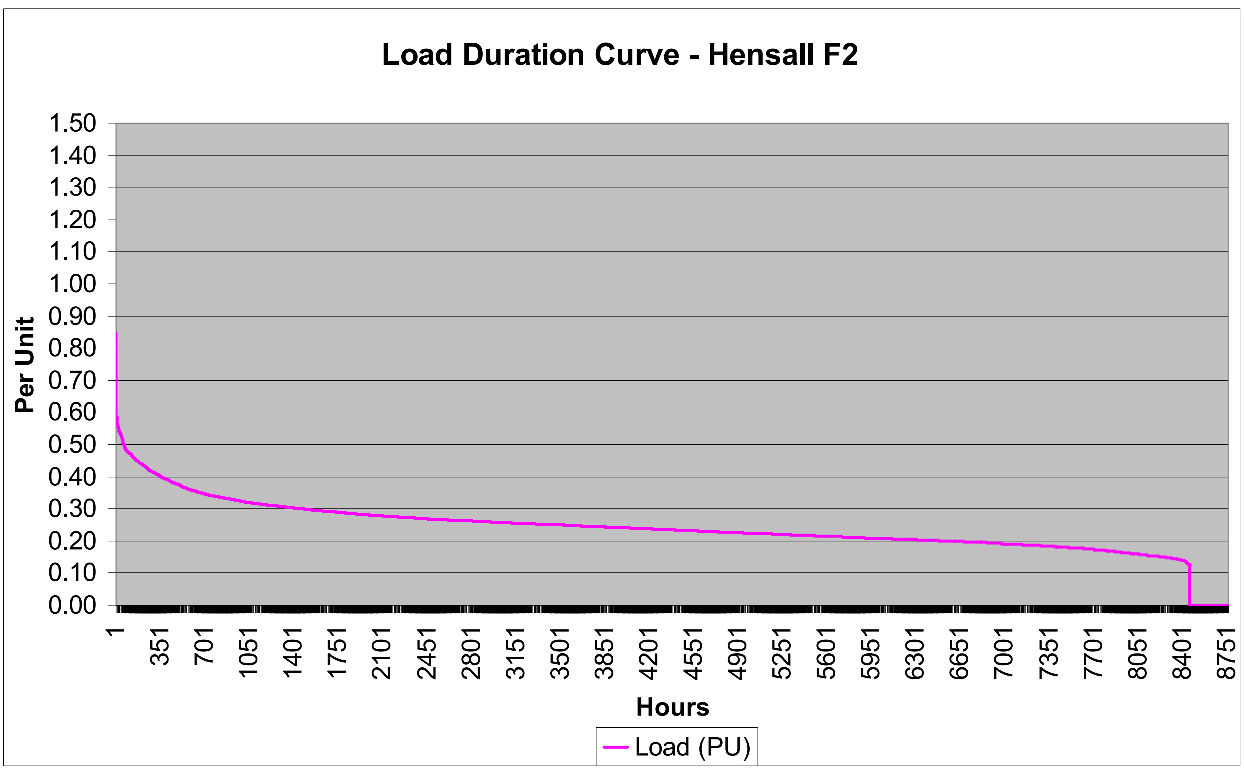
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Hensall F2
Per Unit
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0.60
0.50
0.40
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0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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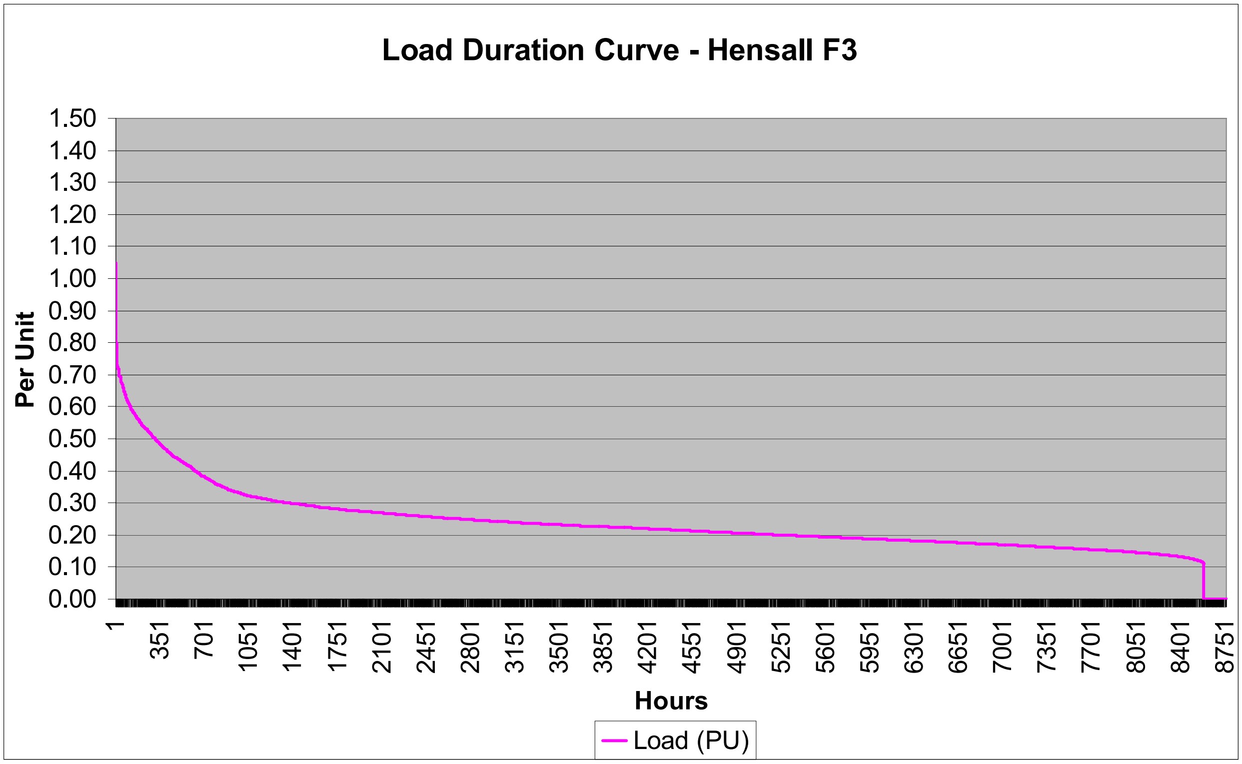
8751
Hours
Load (PU)



Load Duration Curve - Hensall F3
Per Unit
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1.00
0.90
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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4201
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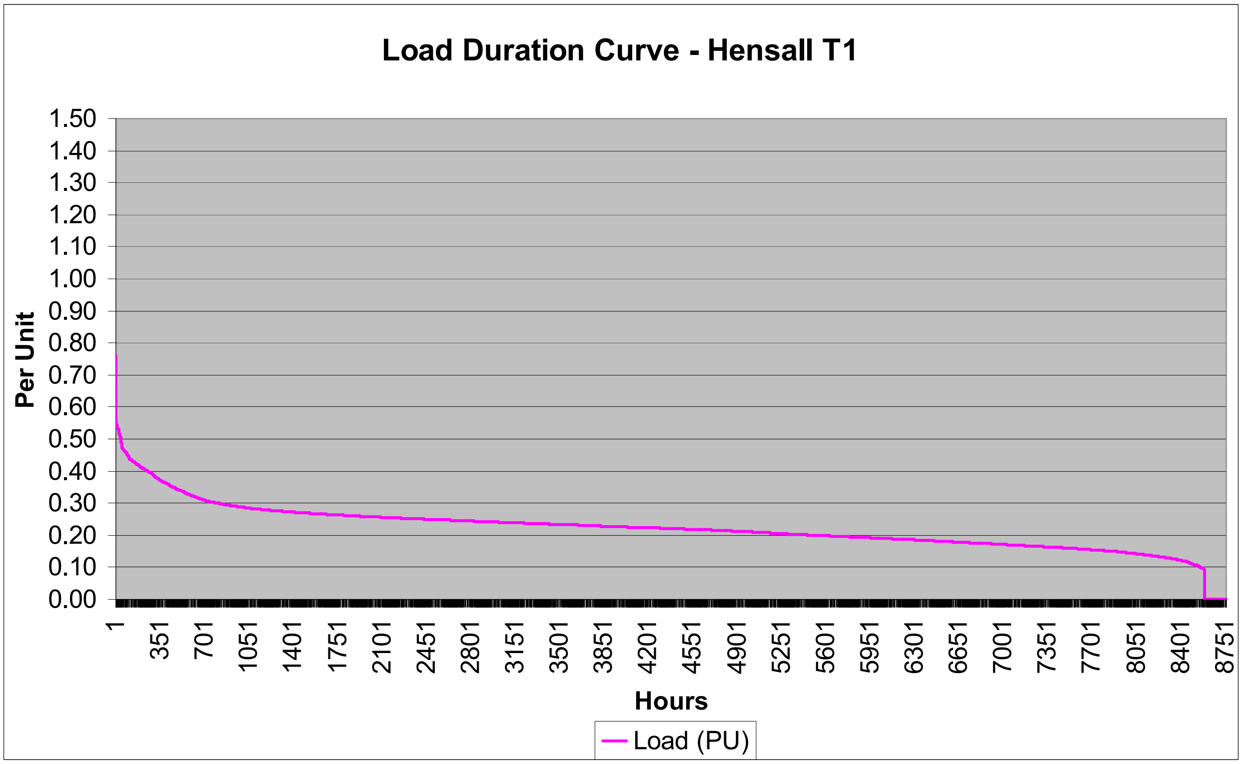
Hours
Load (PU)



Load Duration Curve - Hensall T1
Per Unit
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
3501
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4201
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8401
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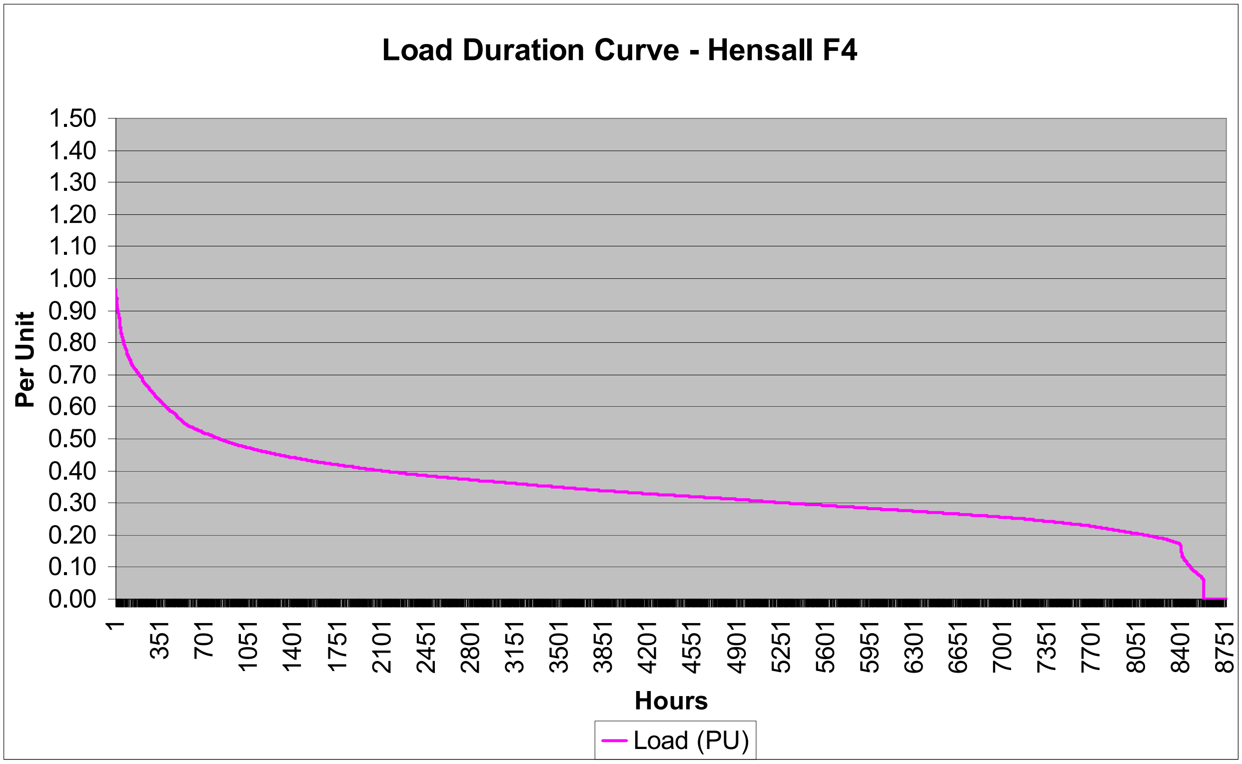
Hours
Load (PU)



Load Duration Curve - Hensall F4
Per Unit
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0.60
0.50
0.40
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0.10
0.00
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351
701
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1401
1751
2101
2451
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3151
3501
3851
4201
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6651
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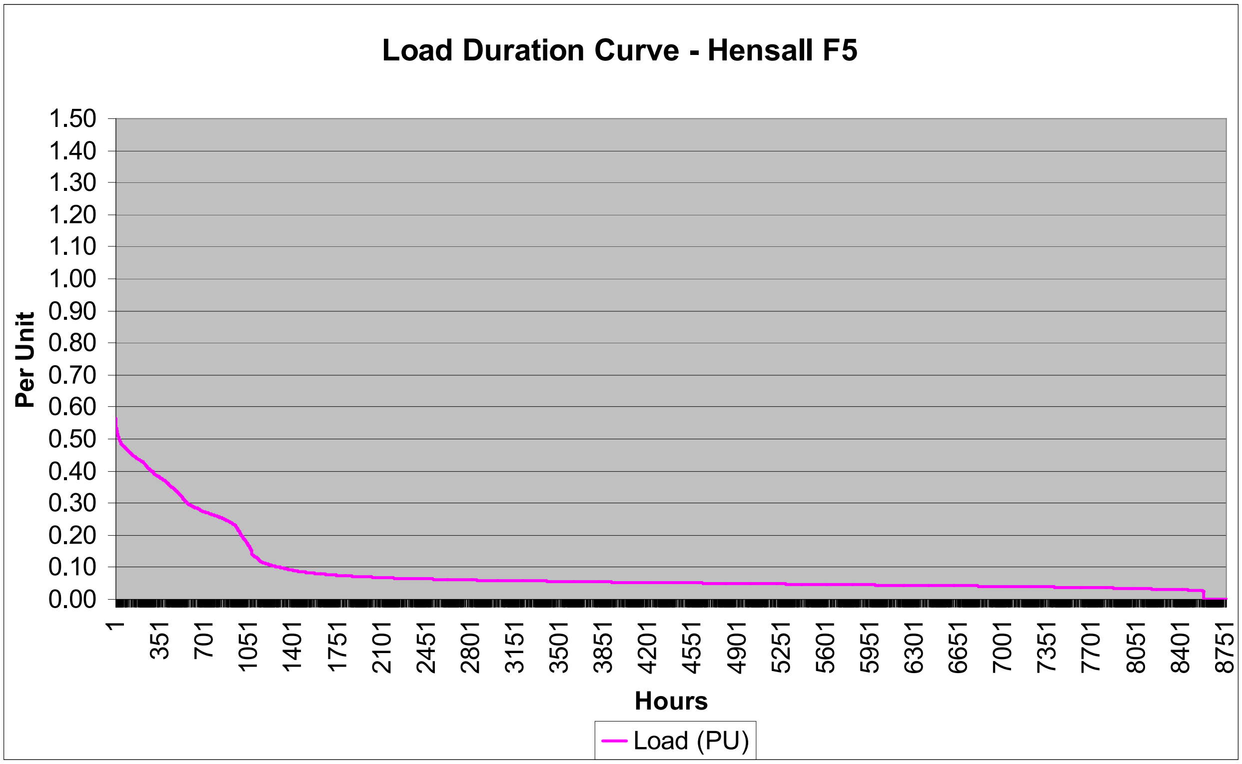
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Hensall F5
Per Unit
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0.80
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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701
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1401
1751
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3151
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3851
4201
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6301
6651
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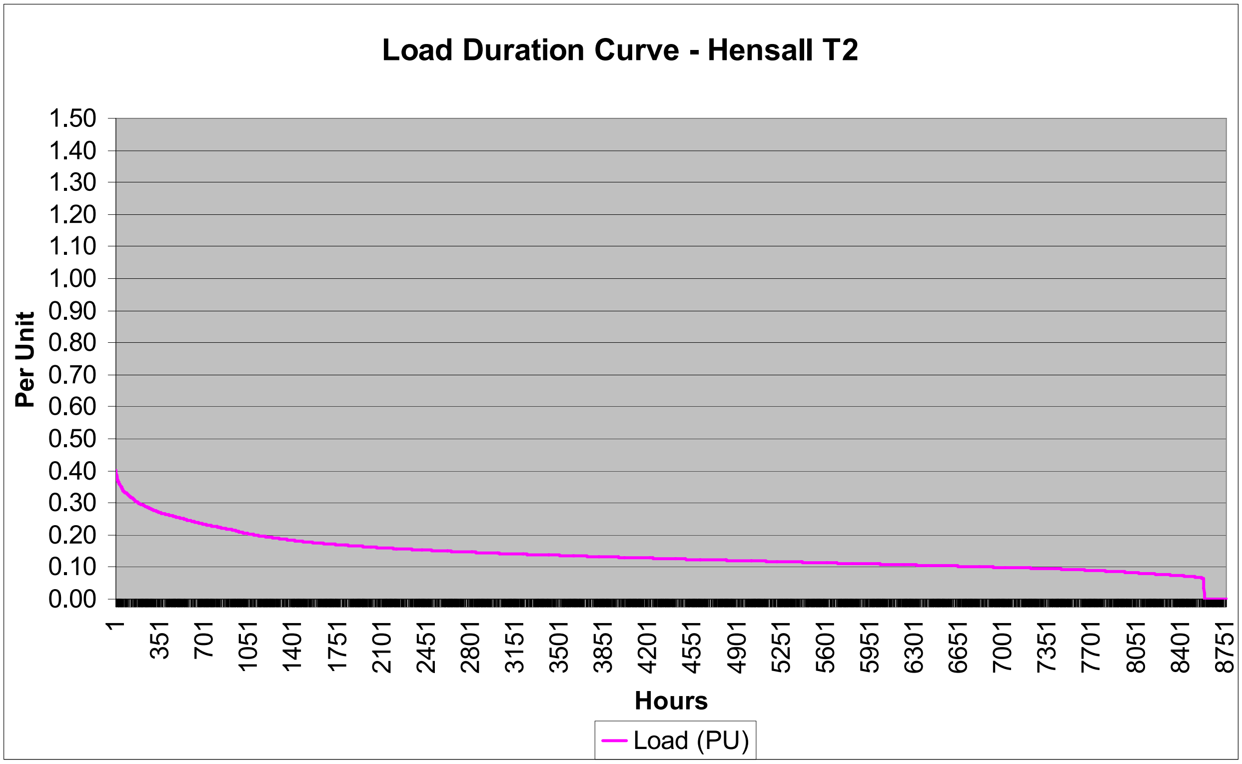
8401
8751
Hours
Load (PU)



Load Duration Curve - Hensall T2
Per Unit
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0.90
0.80
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
3501
3851
4201
4551
4901
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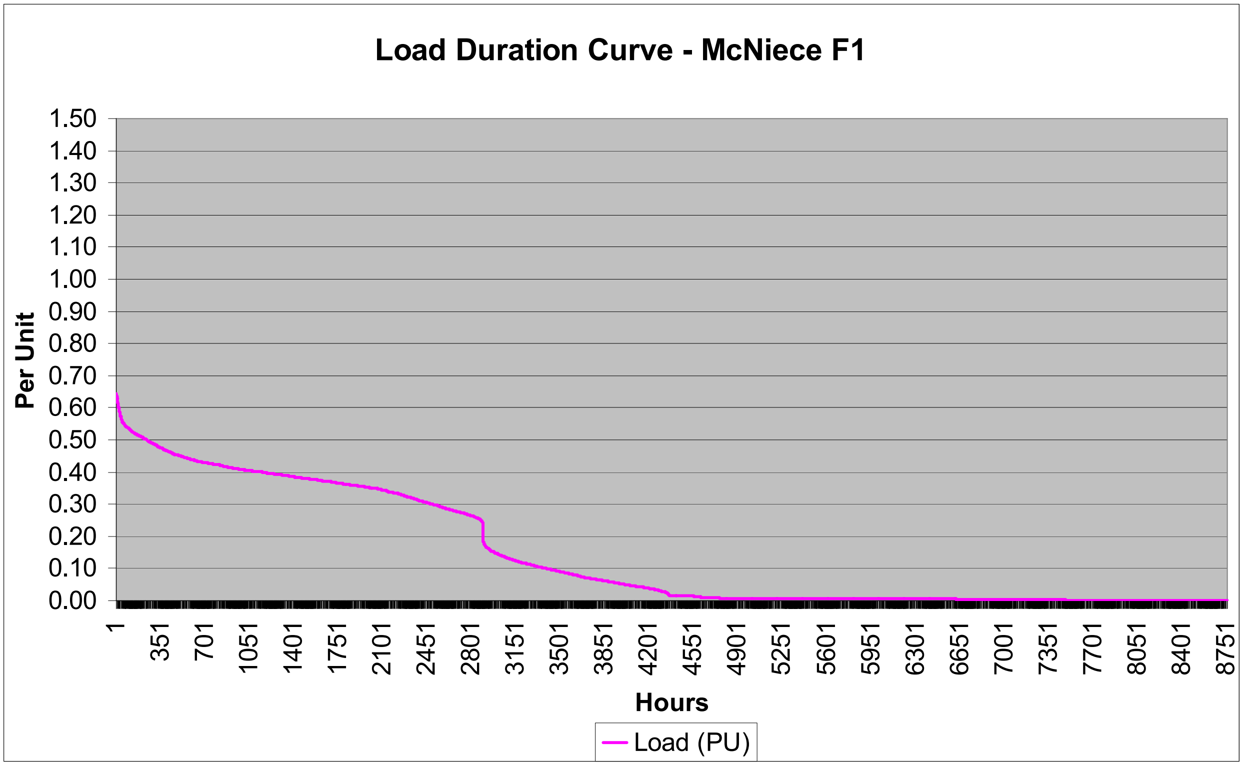
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

McNiece MS


Load Duration Curve - McNiece F1
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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8401
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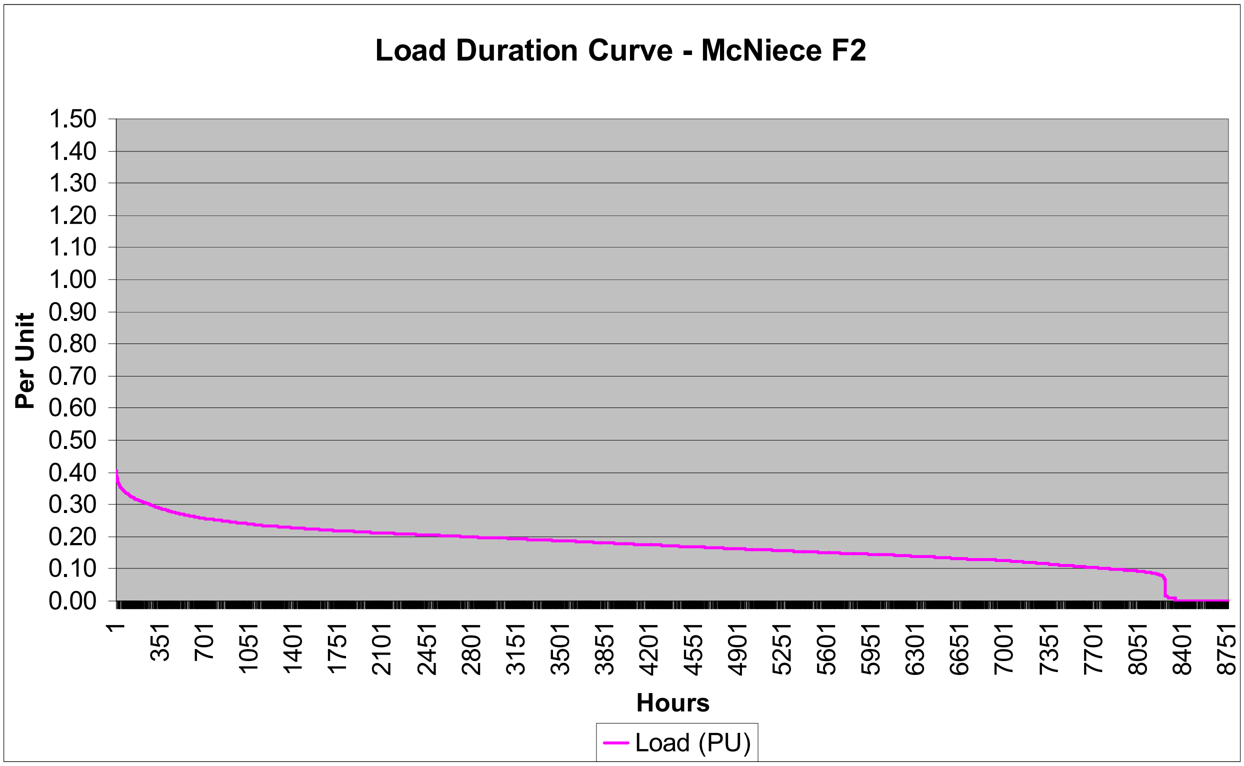
Hours
Load (PU)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0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
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2801
3151
3501
3851
4201
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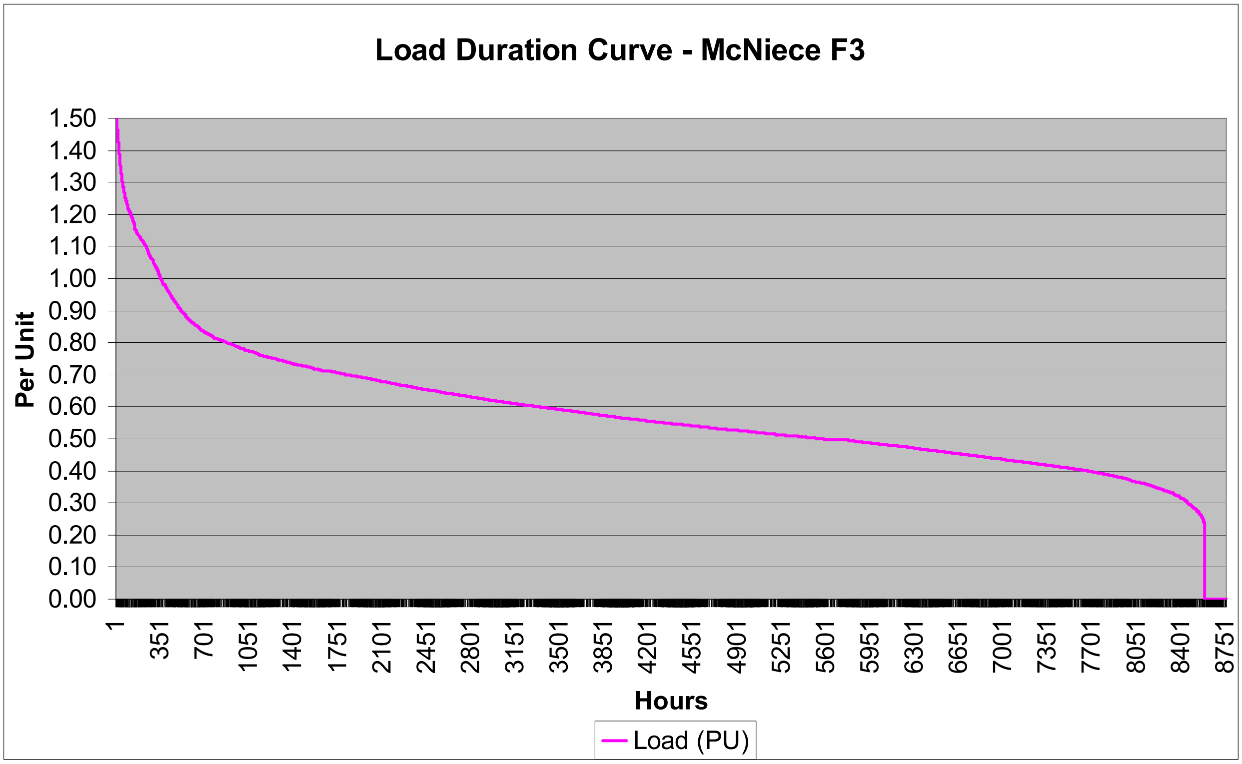
8401
8751
Hours
Load (PU)



Load Duration Curve - McNiece F3
Per Unit
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0.30
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0.10
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1
351
701
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3501
3851
4201
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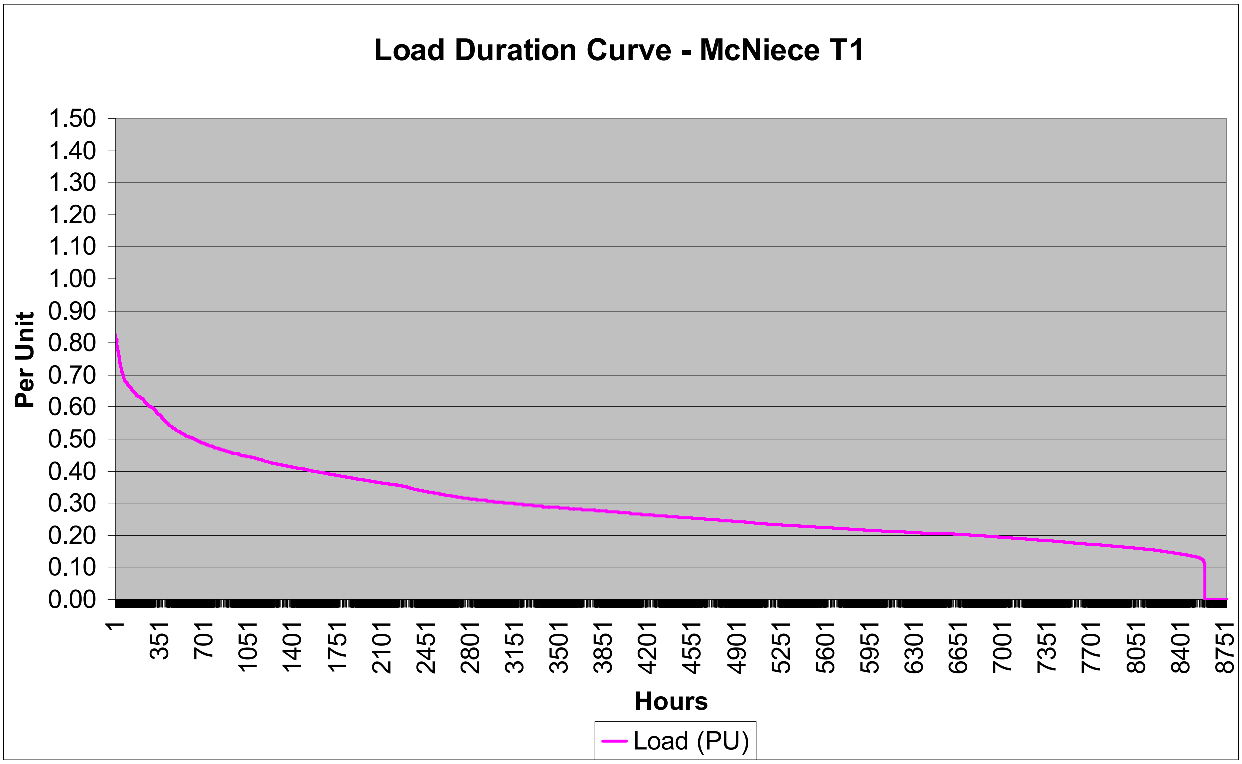
8401
8751
Hours
Load (PU)



Load Duration Curve - McNiece T1
Per Unit
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
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701
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1401
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2451
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3851
4201
4551
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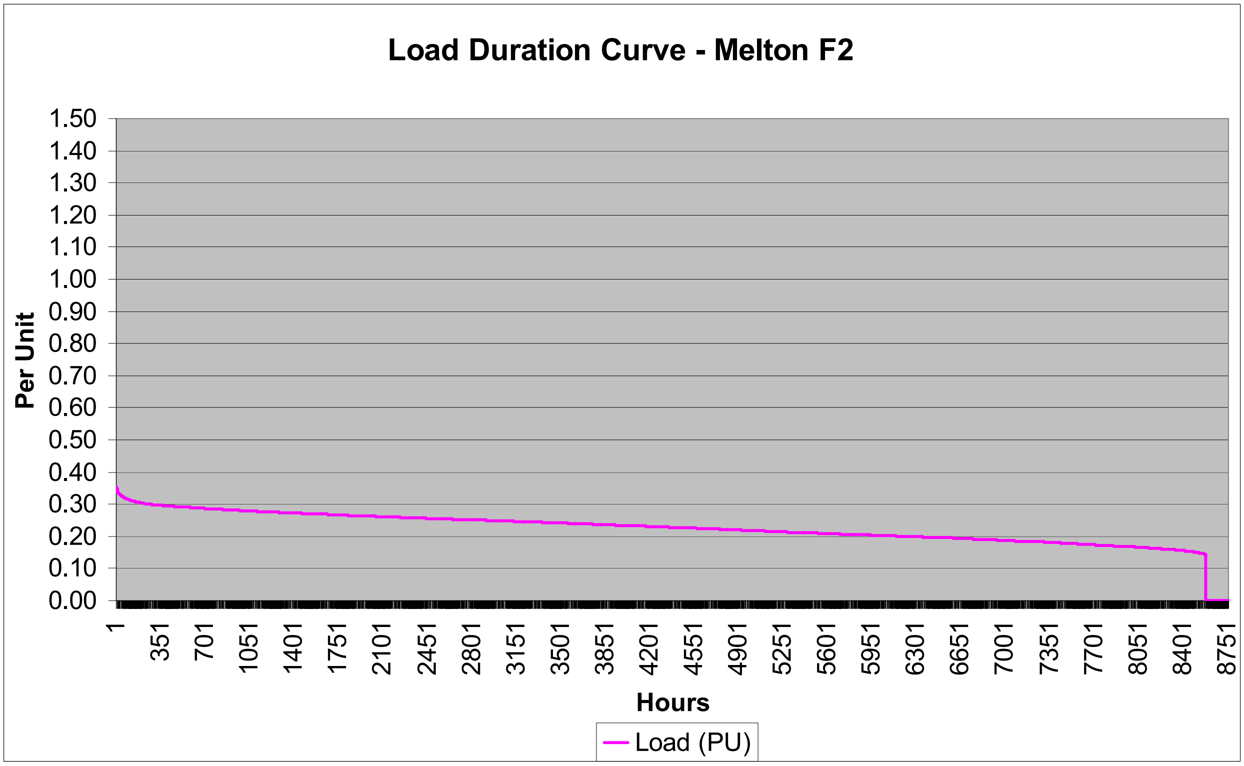
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Melton MS



Load Duration Curve - Melton F2
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0.50
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0.30
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0.10
0.00
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351
701
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8401
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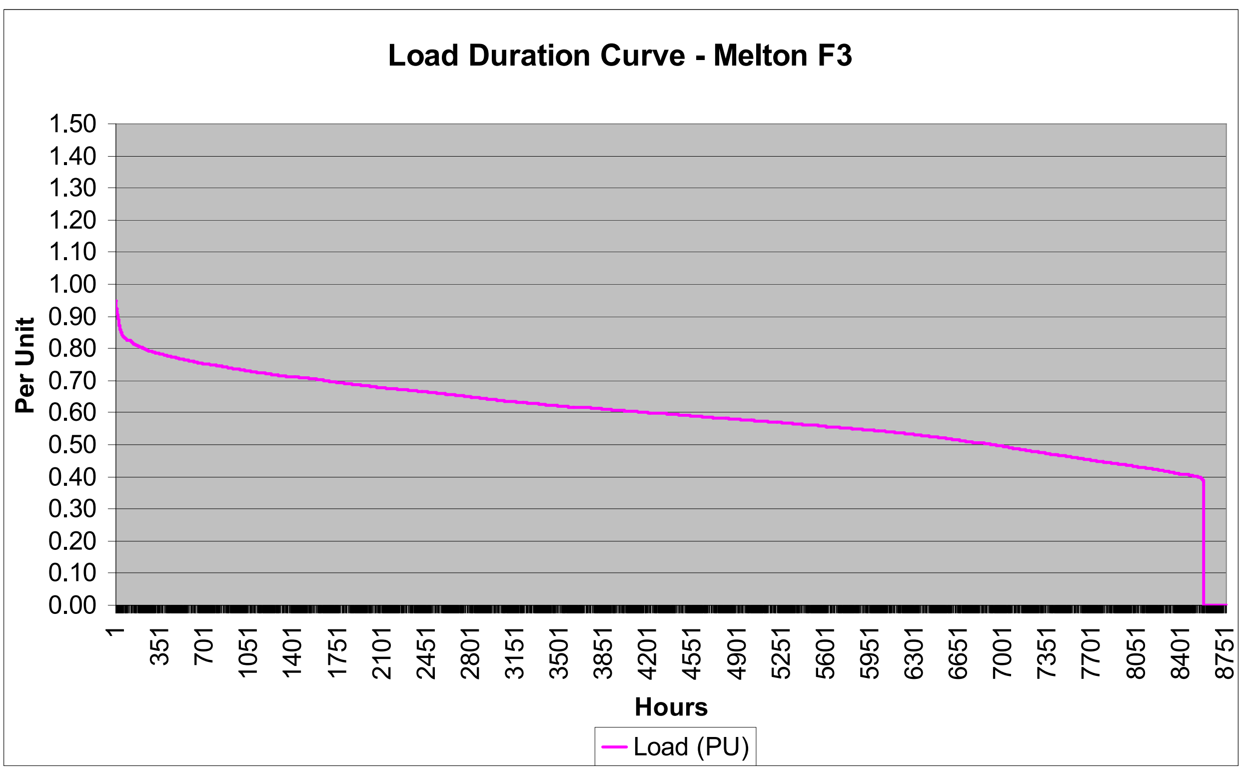
Hours
Load (PU)



Load Duration Curve - Melton F3
Per Unit
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
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0.10
0.00
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351
701
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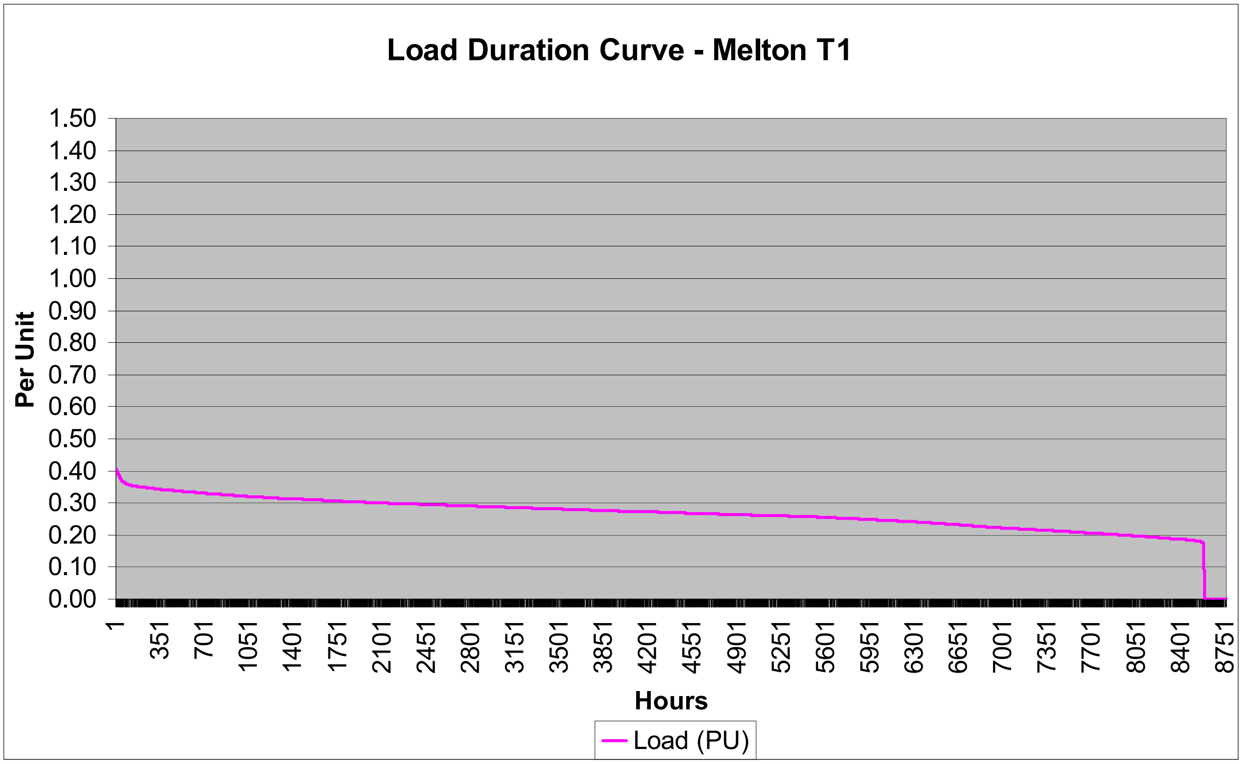
Hours
Load (PU)



Load Duration Curve - Melton T1
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0.80
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
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3151
3501
3851
4201
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8051
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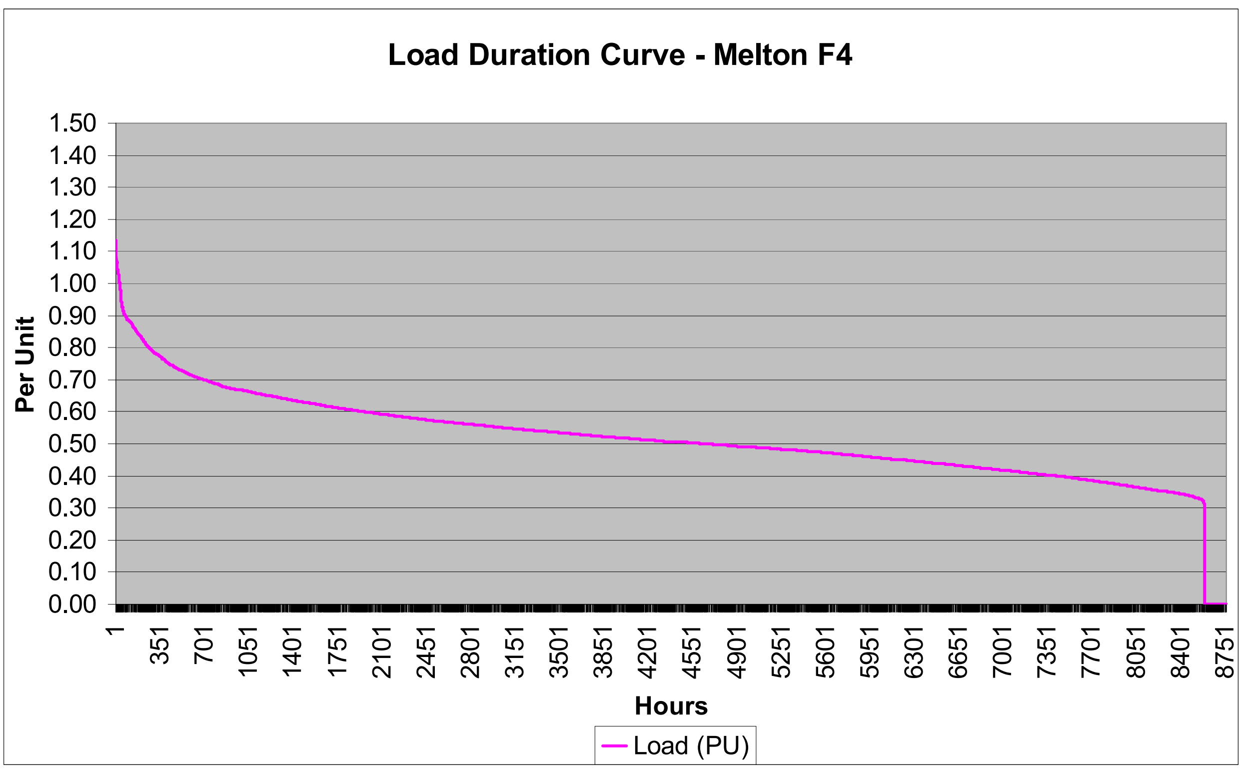
Hours
Load (PU)



Load Duration Curve - Melton F4
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0.40
0.30
0.20
0.10
0.00
Per Unit
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701
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3851
4201
4551
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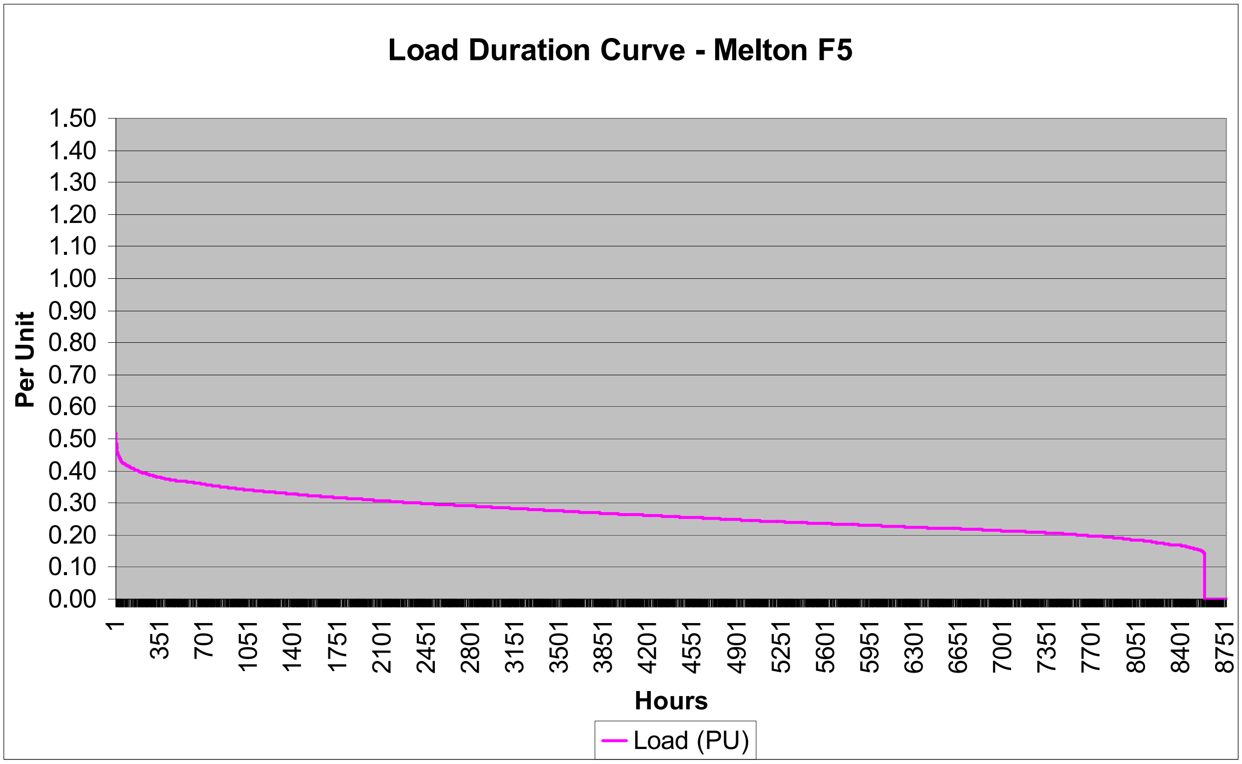
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Melton F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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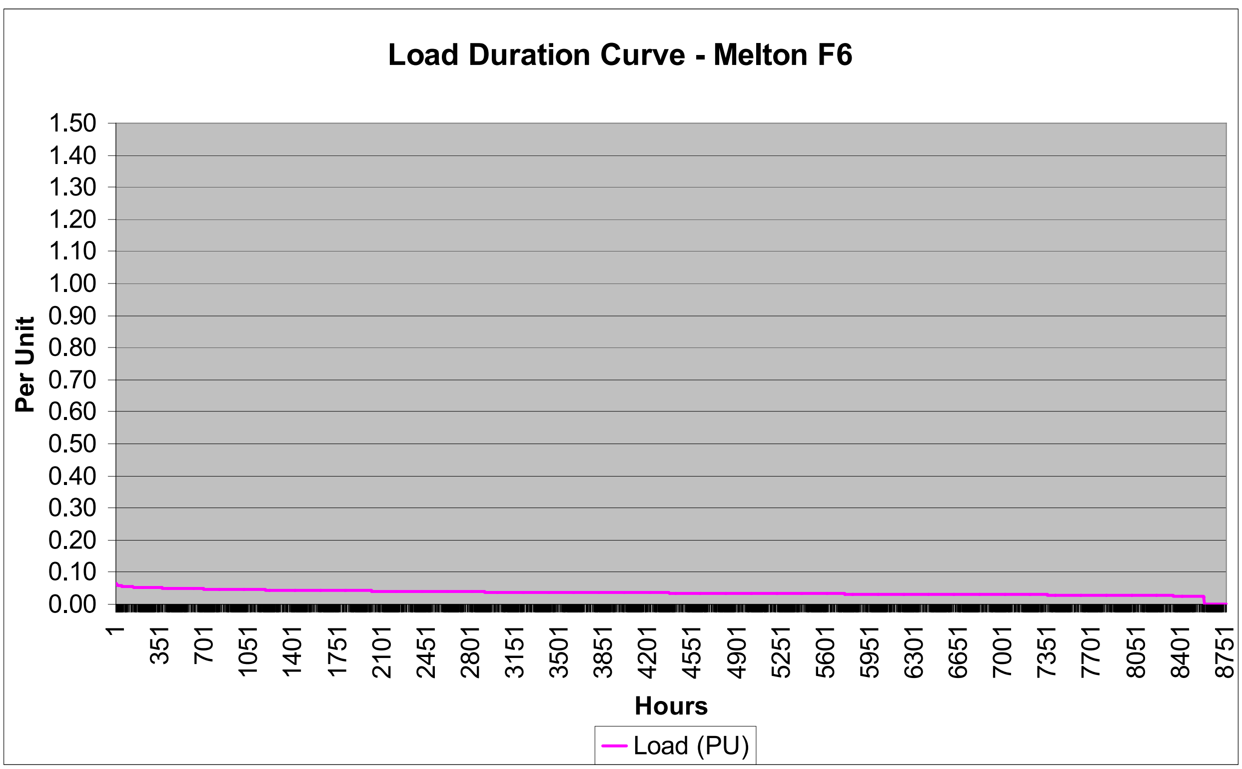
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Melton F6
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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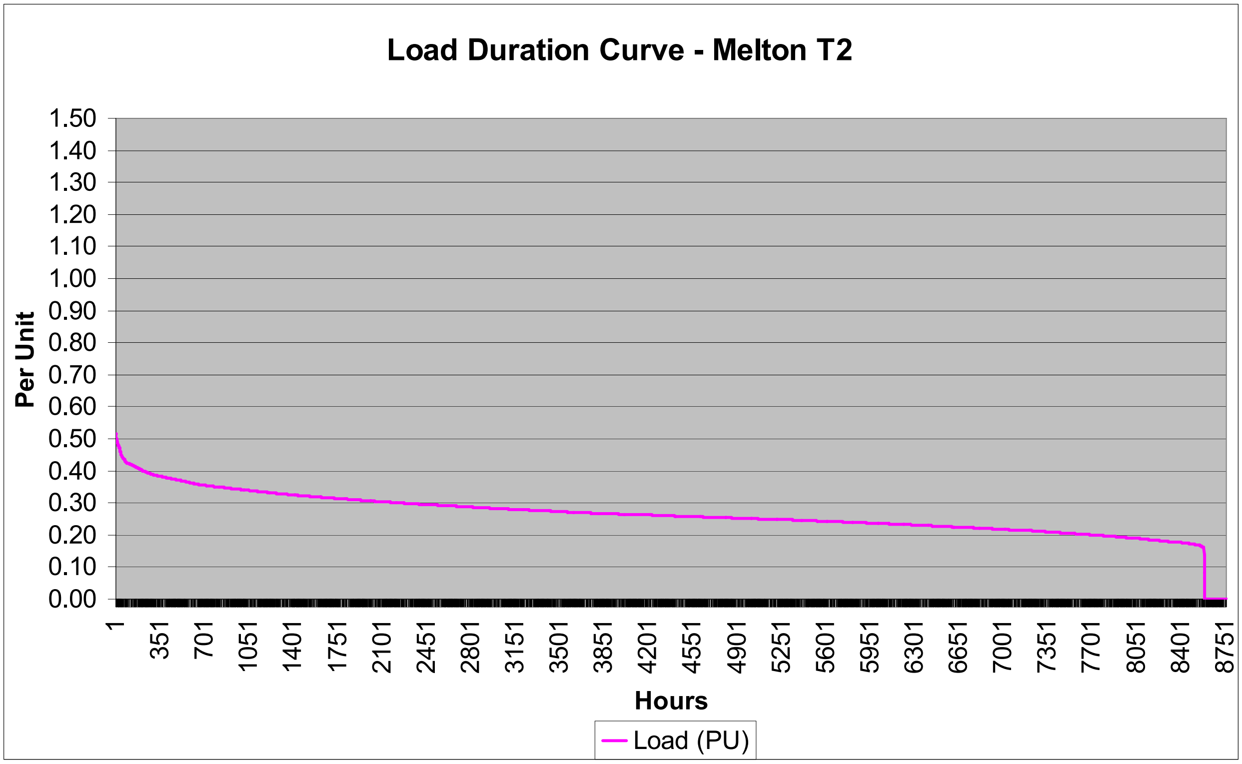
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Melton T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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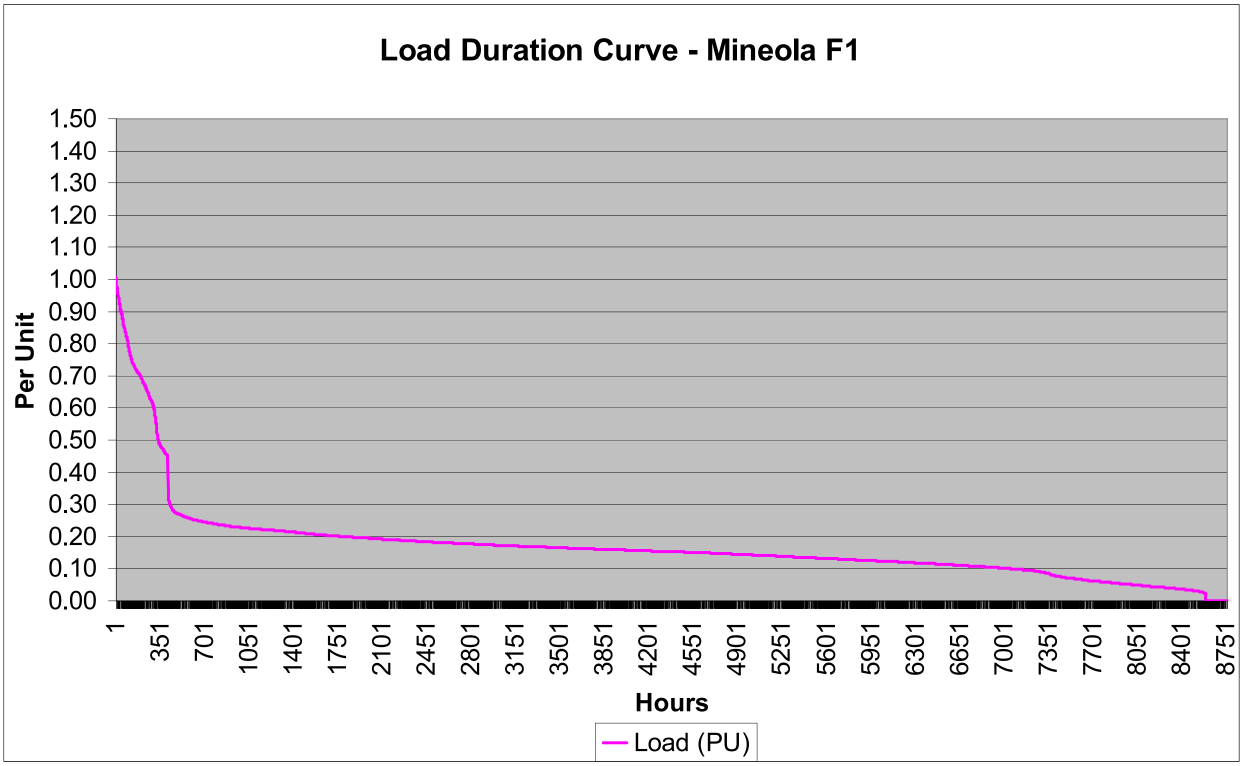
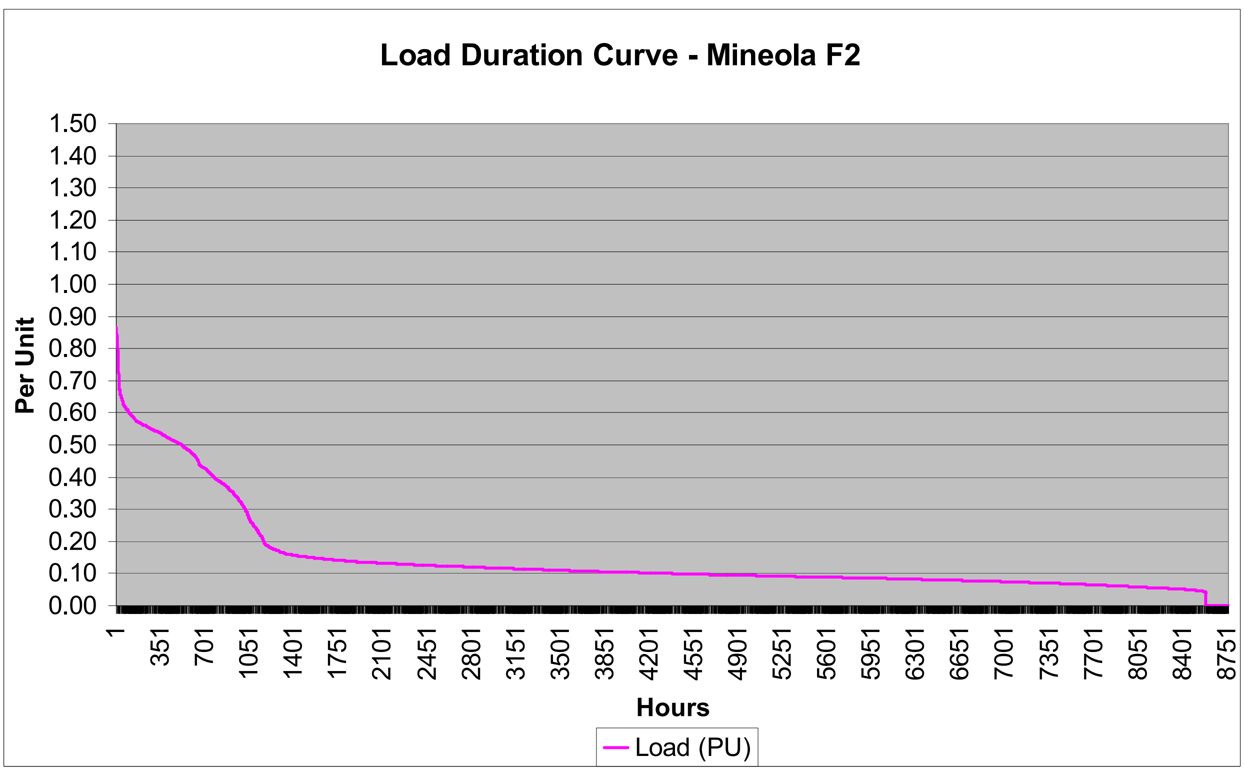
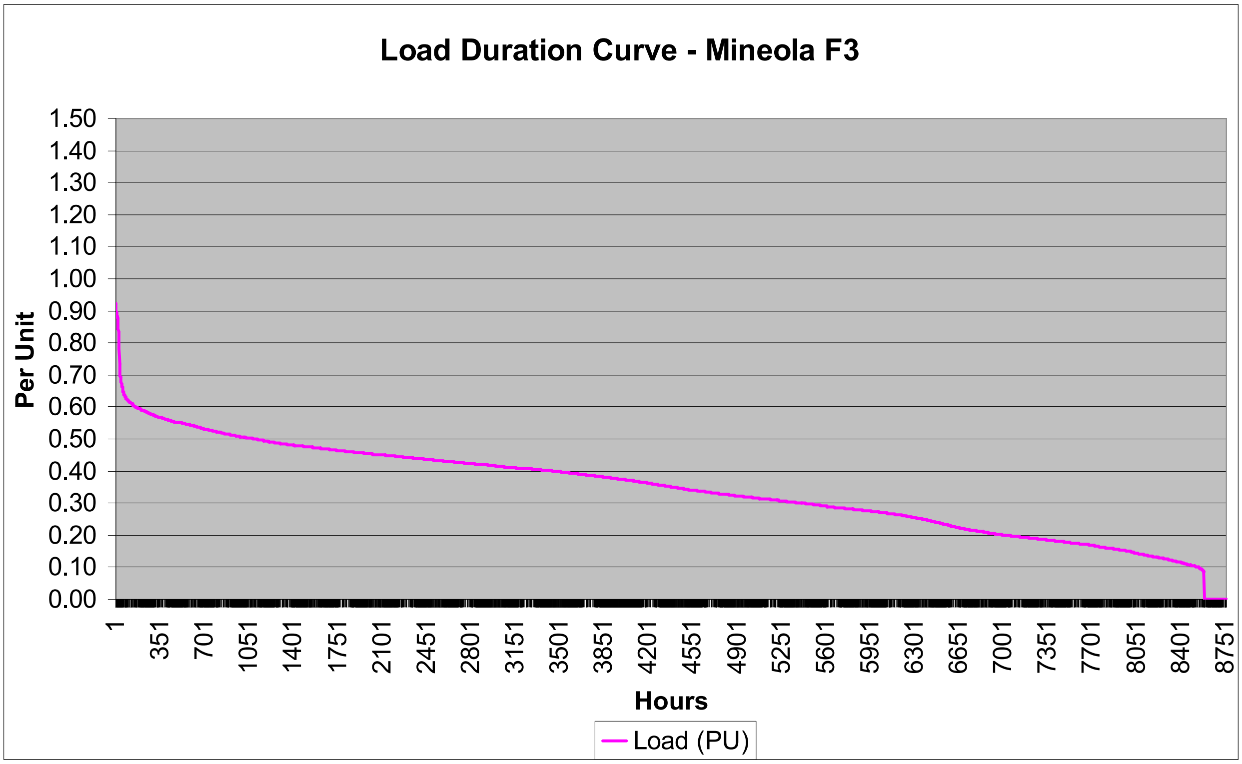
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

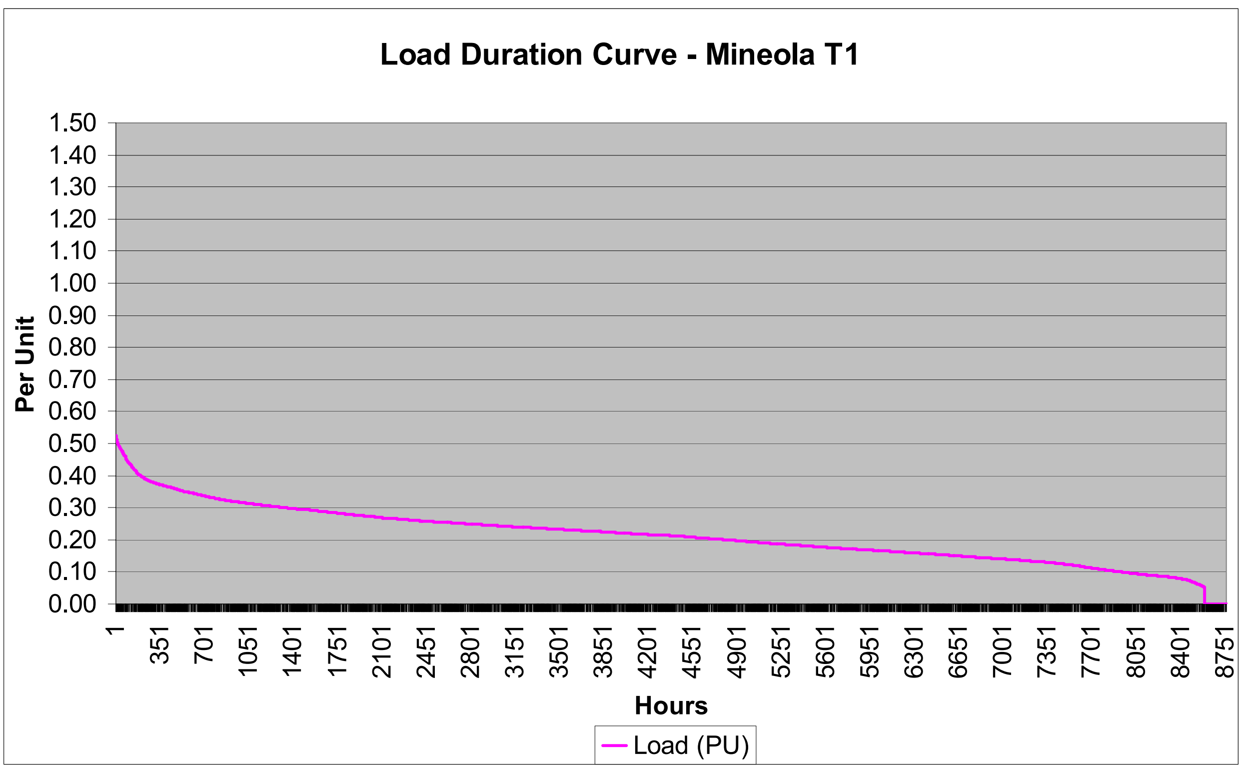
Mineola MS


Load Duration Curve - Mineola F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

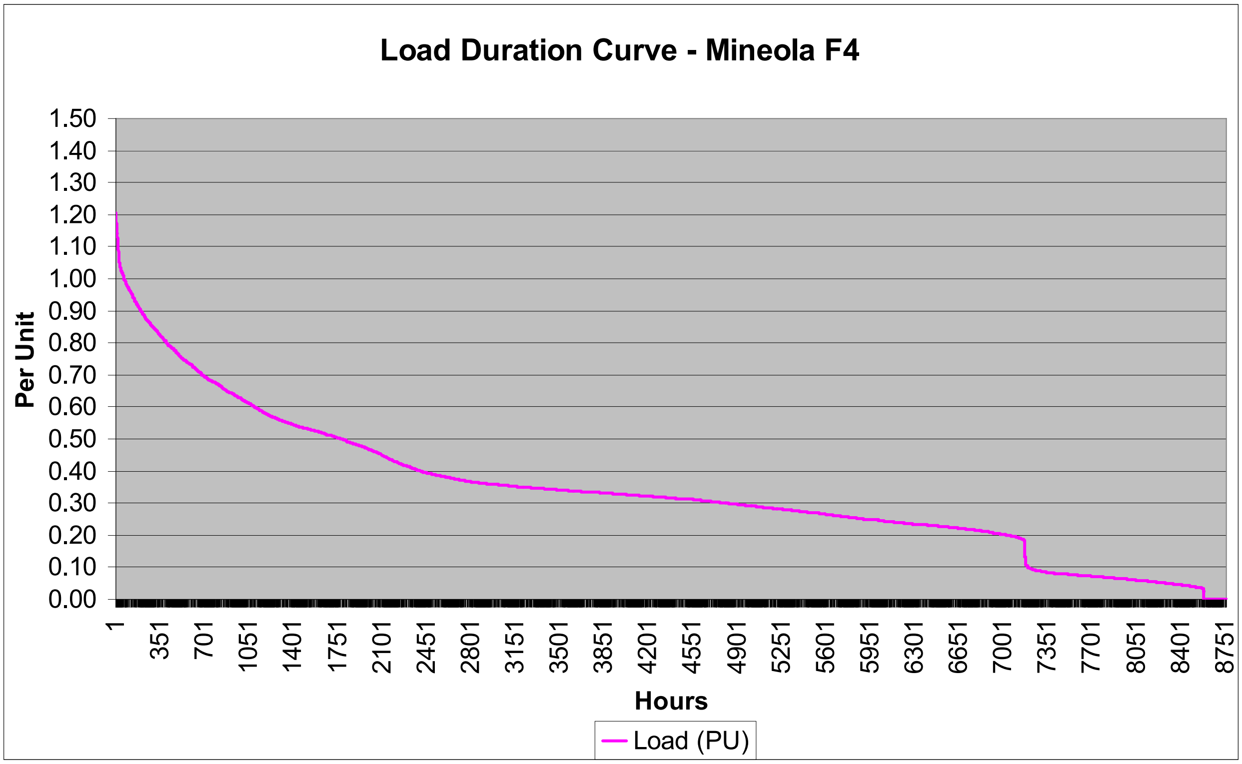

Load Duration Curve - Mineola F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Mineola F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Mineola T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Mineola F4
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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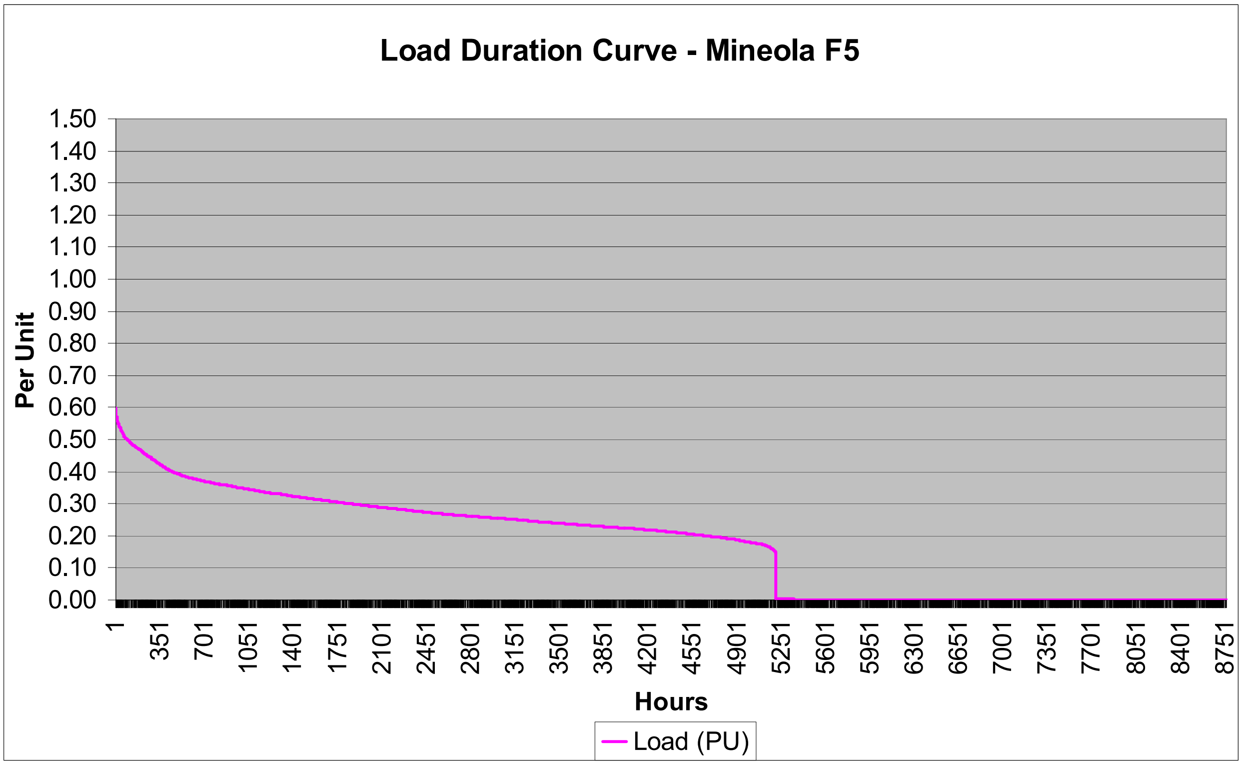
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Mineola F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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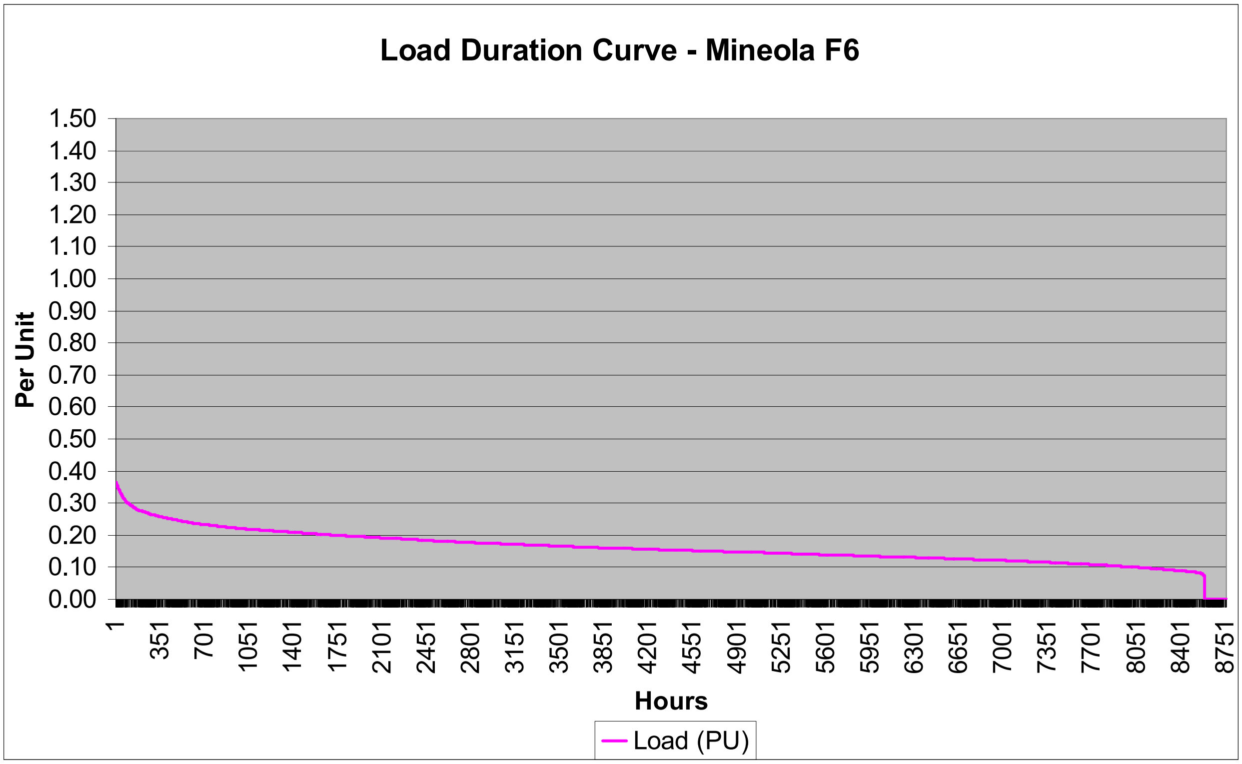
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Mineola F6
Per Unit
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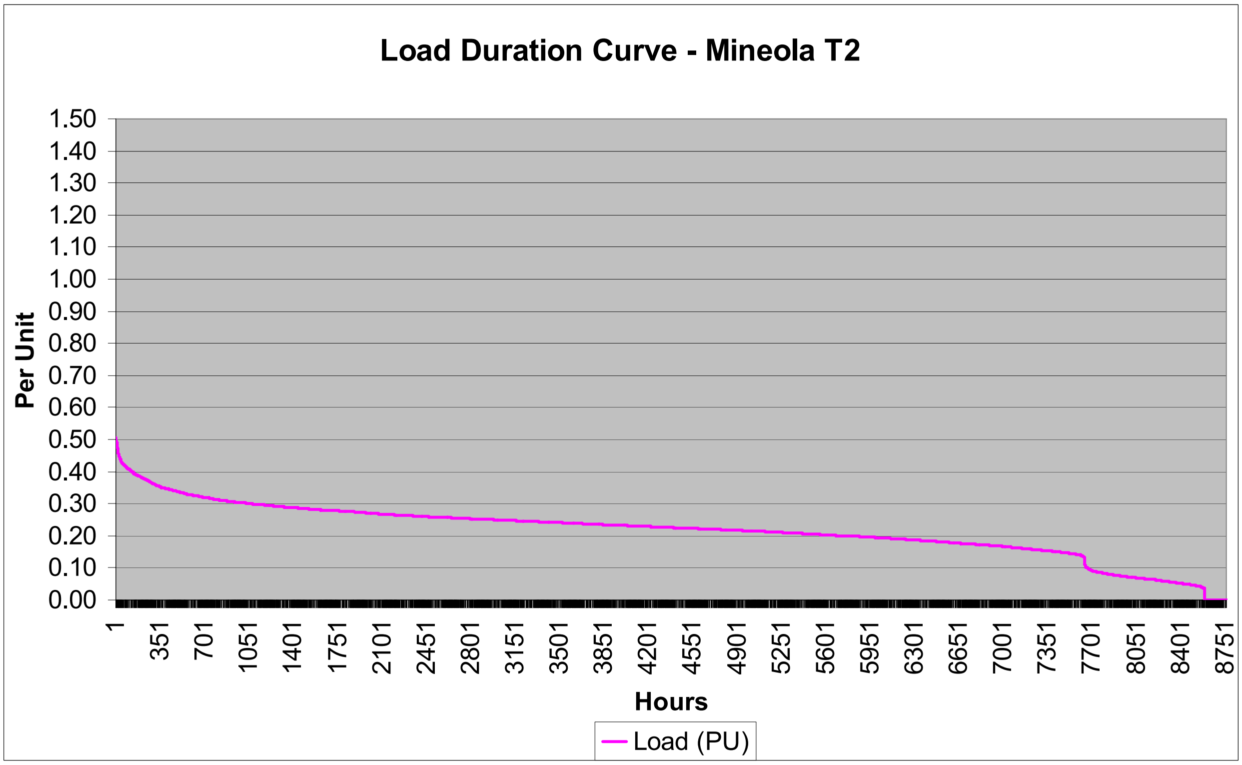
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Mineola T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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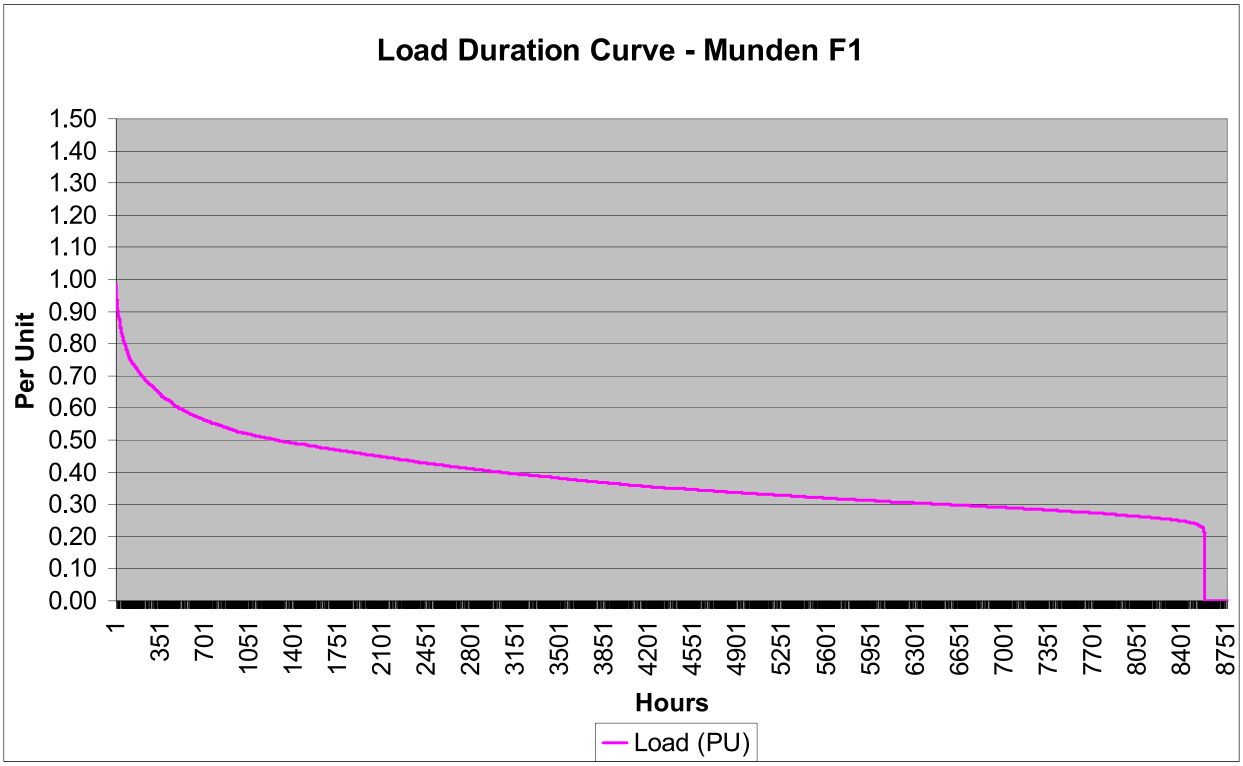
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Munden MS


Load Duration Curve - Munden F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
3501
3851
4201
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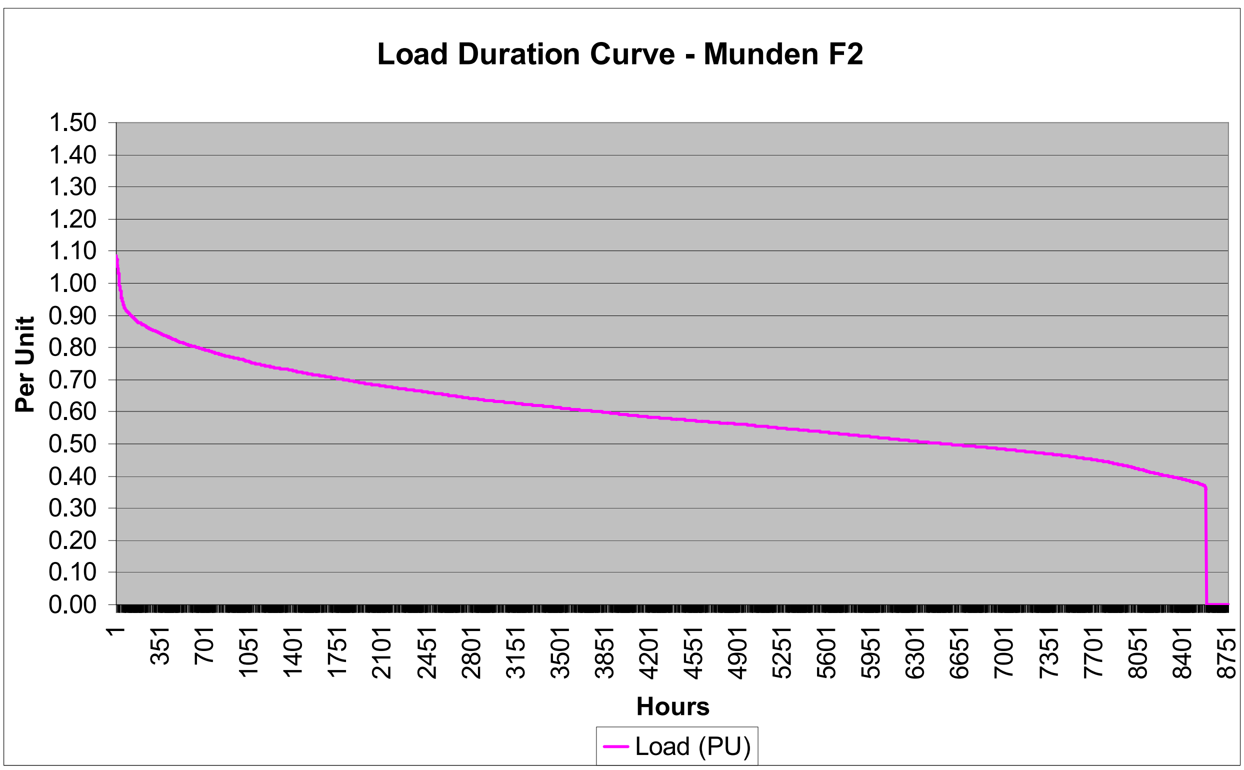
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Munden F2
Per Unit
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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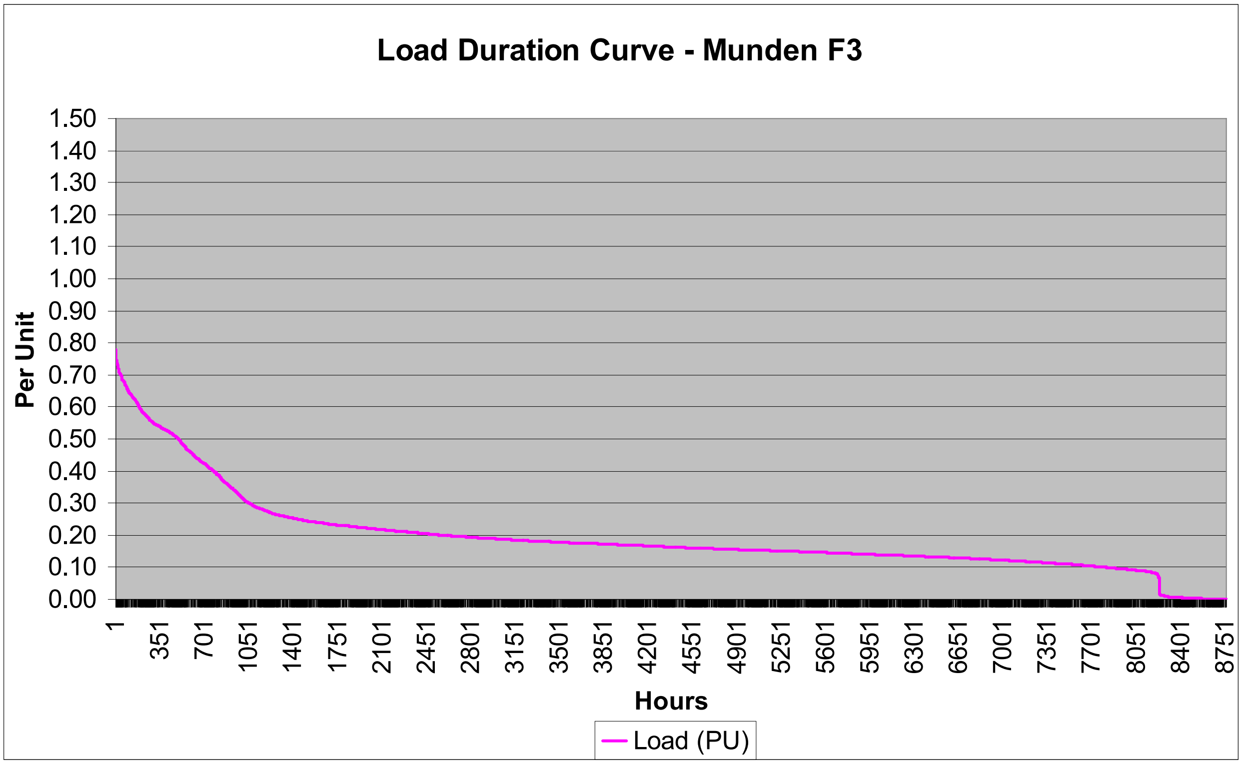
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Munden F3
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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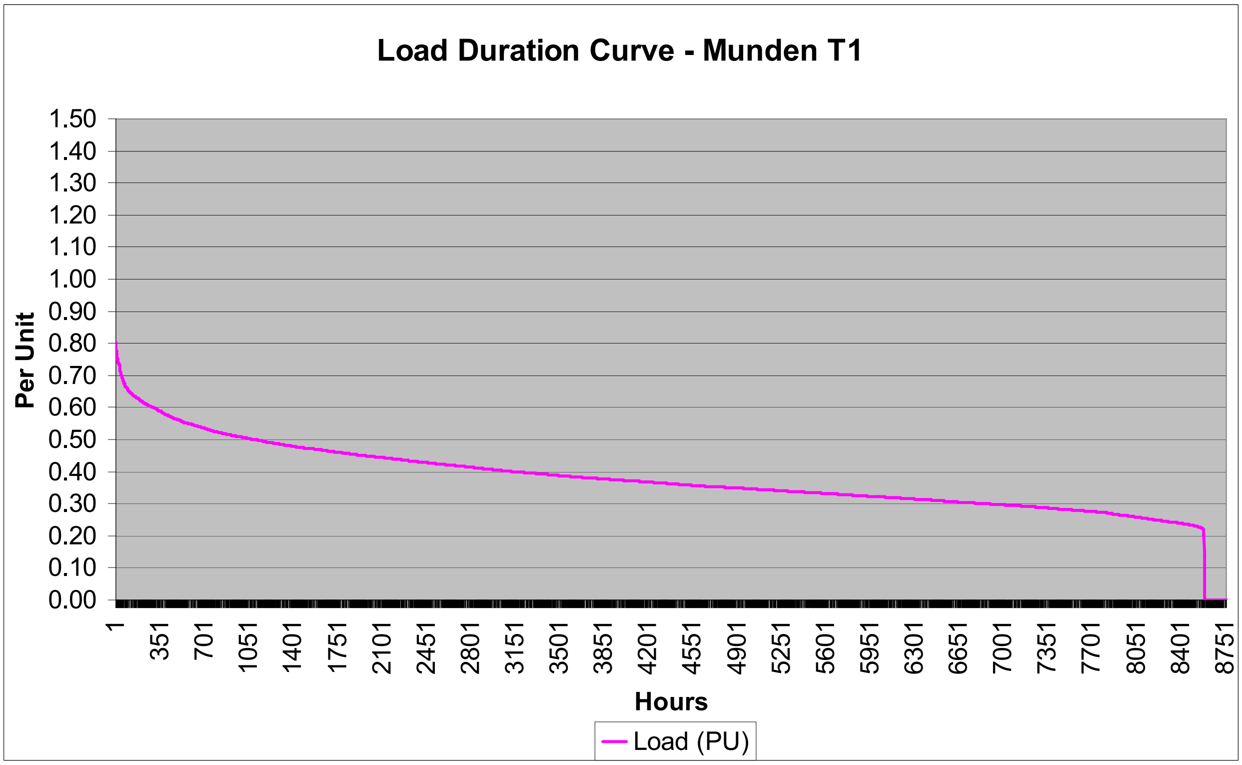
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Munden T1
1.50
1.40
1.30
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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5601
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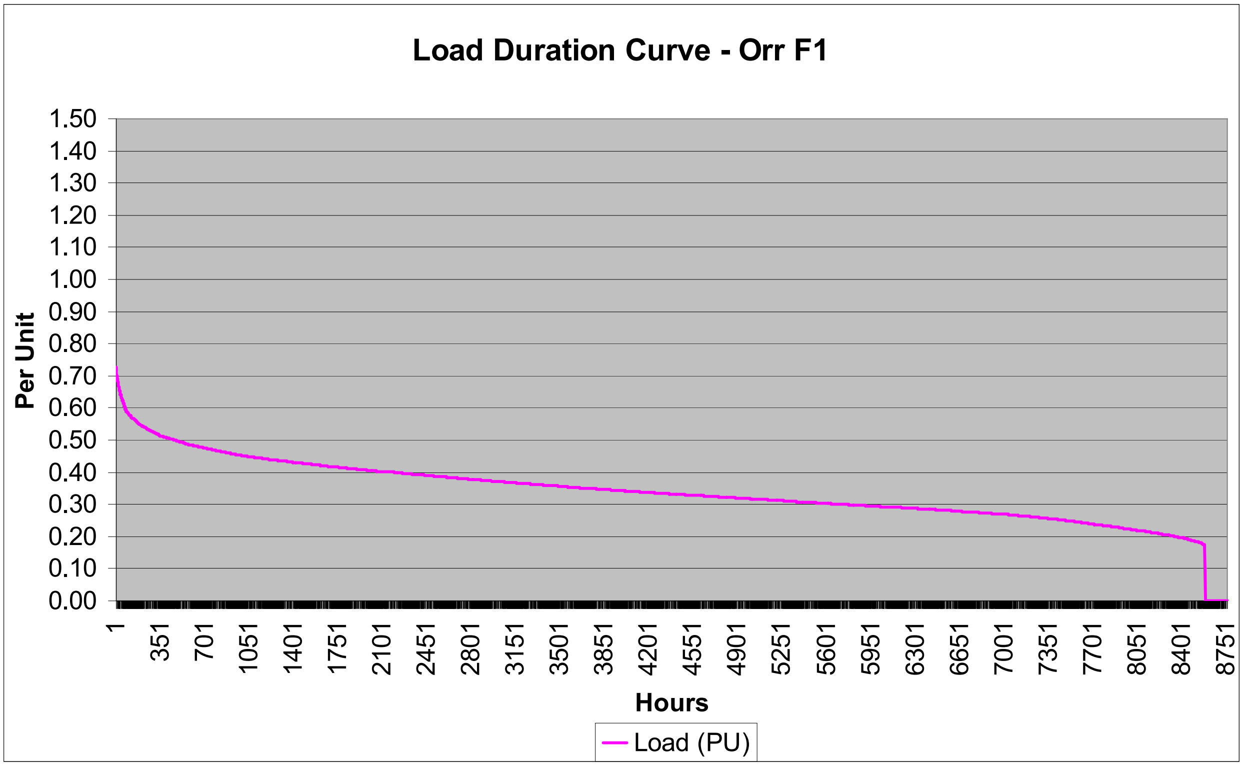
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Orr MS


Load Duration Curve - Orr F1
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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2101
2451
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3151
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3851
4201
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6651
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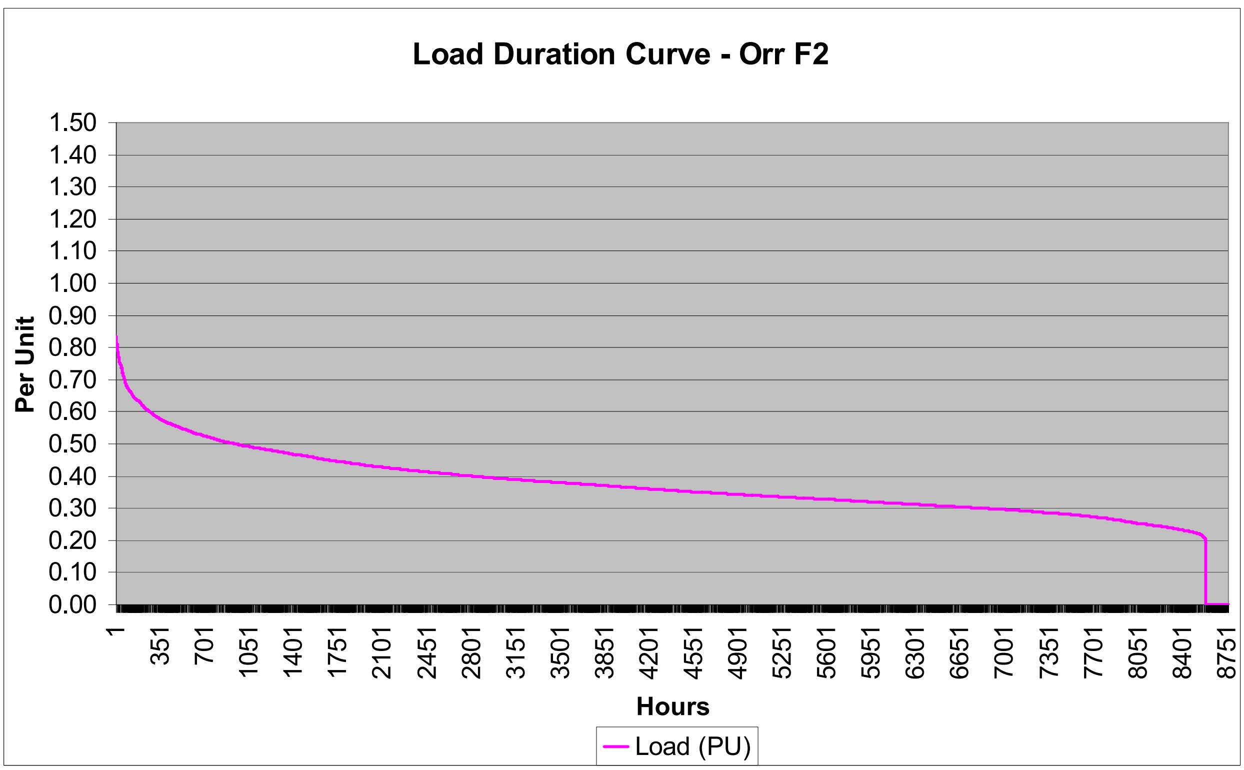
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Orr F2
Per Unit
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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2101
2451
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3151
3501
3851
4201
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6651
7001
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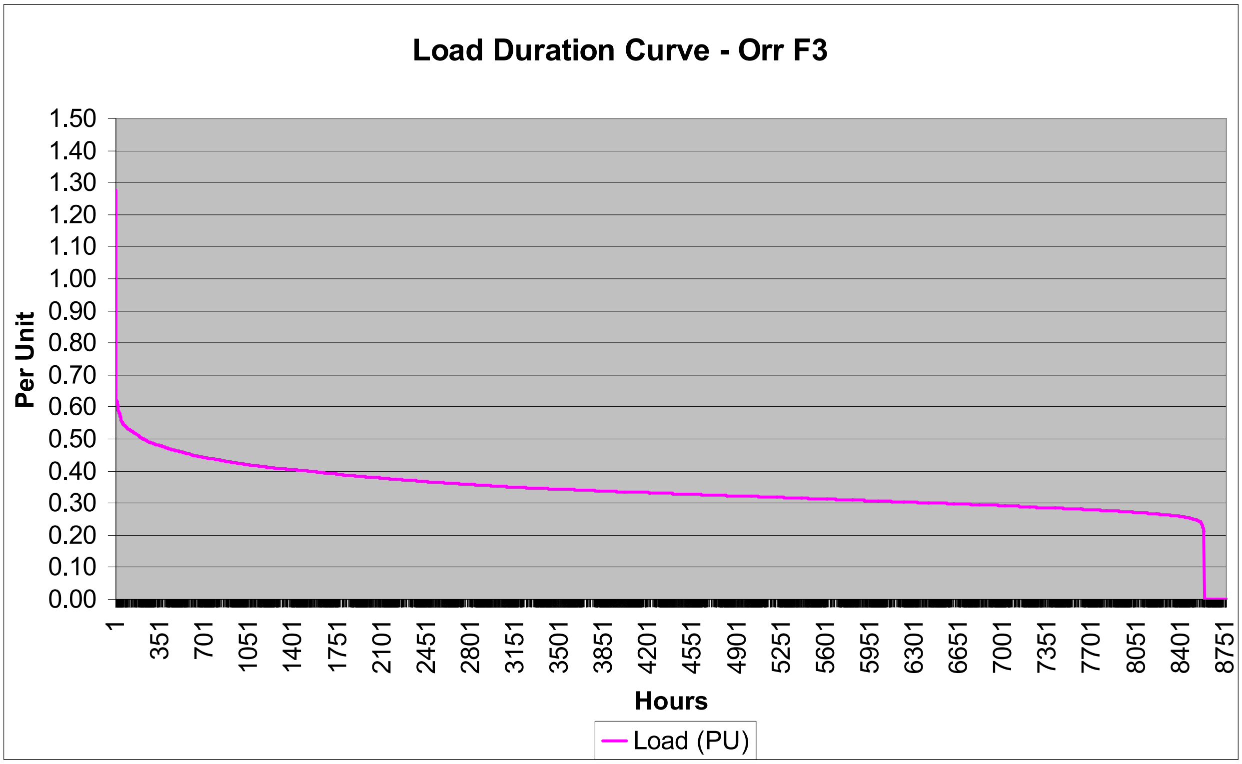
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Orr F3
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1.10
1.00
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6301
6651
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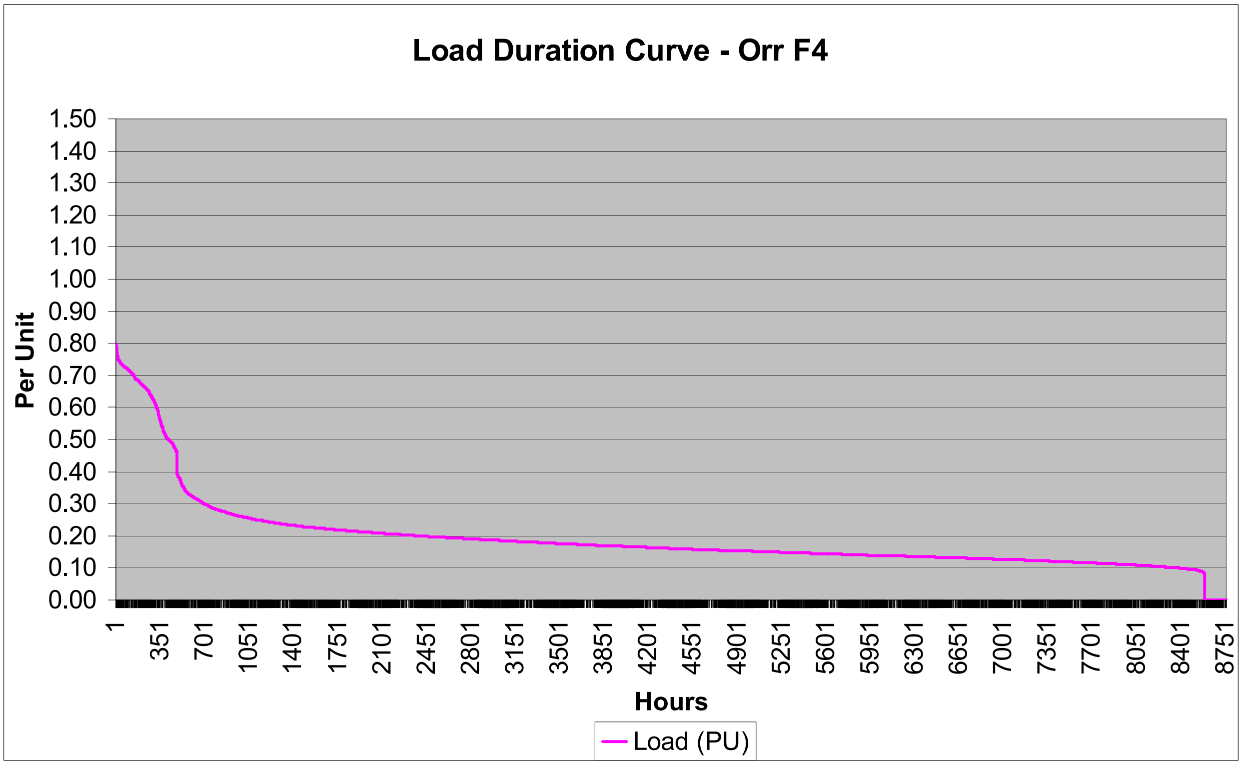
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Orr F4
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1.00
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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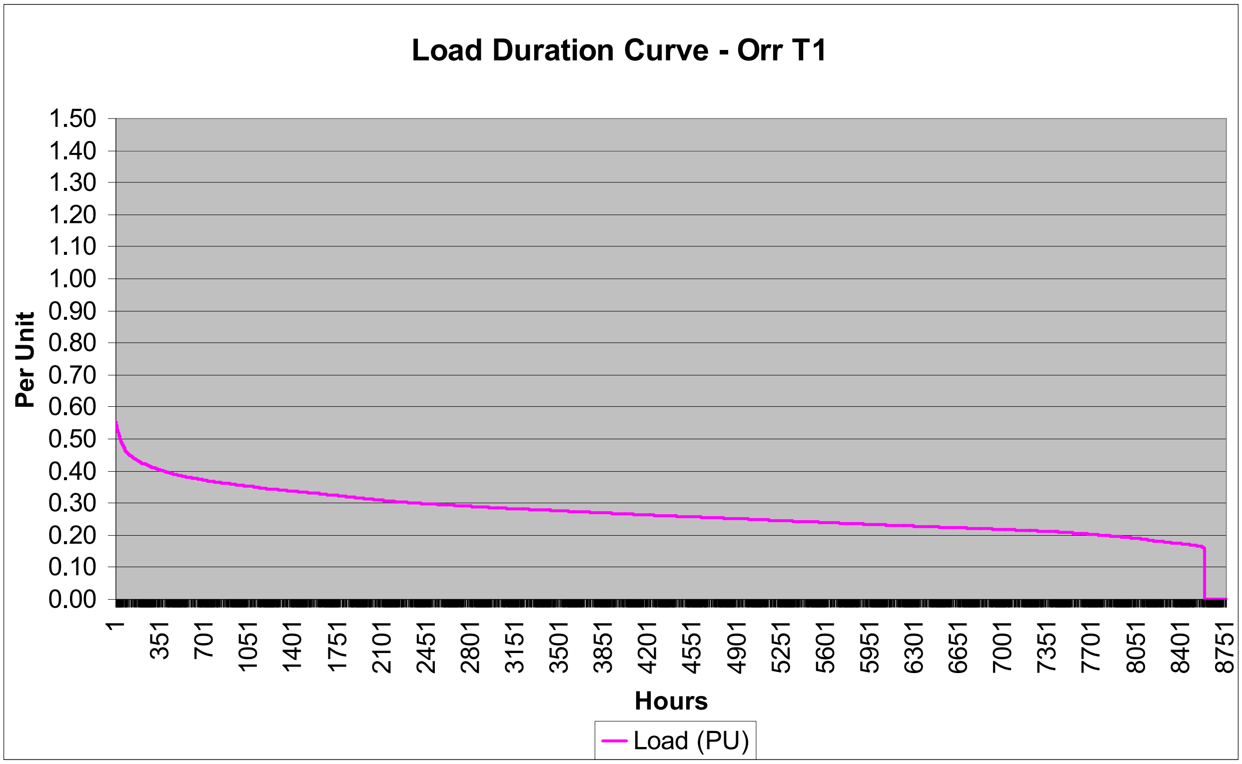
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Orr T1
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
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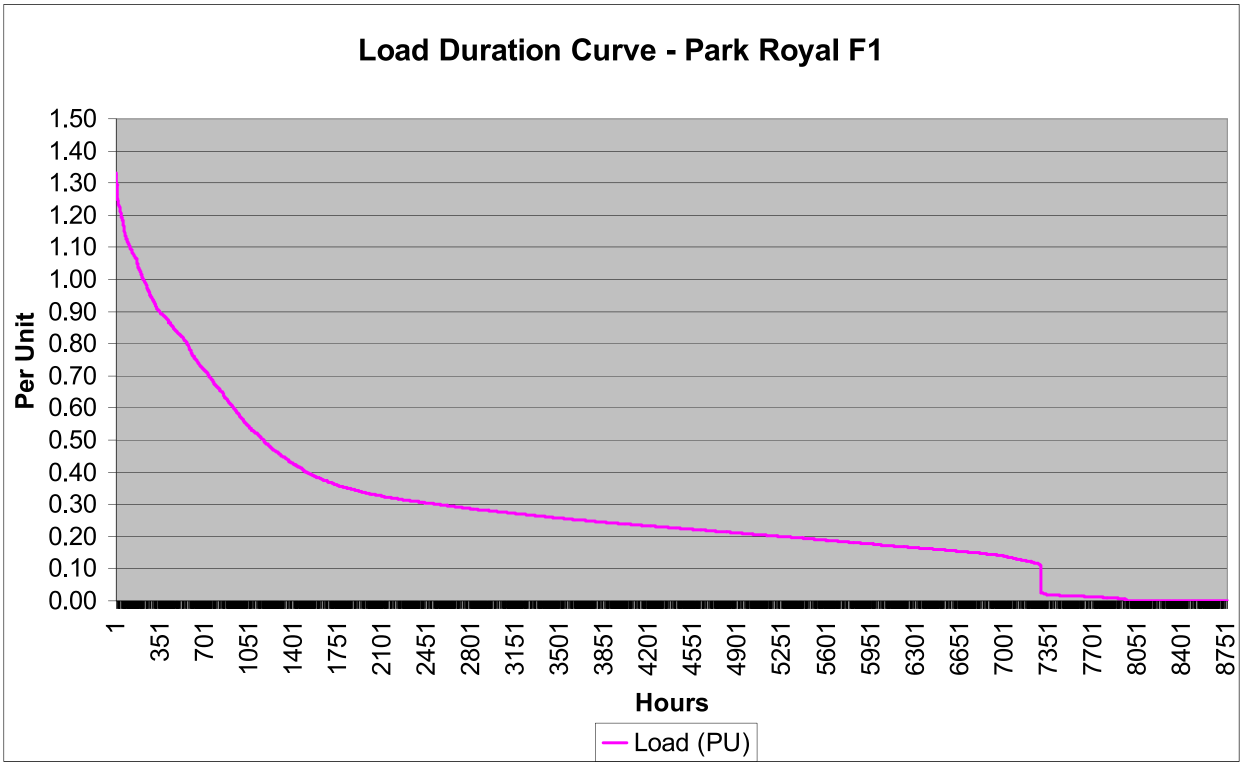
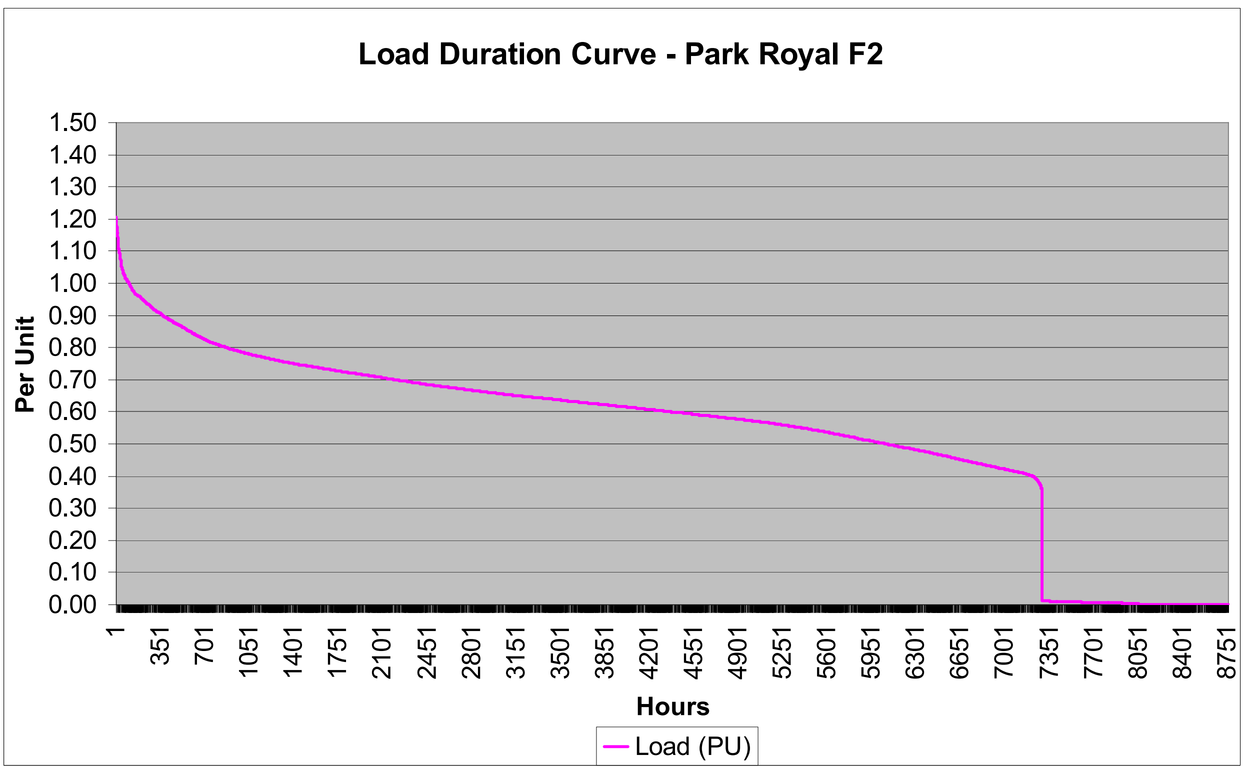
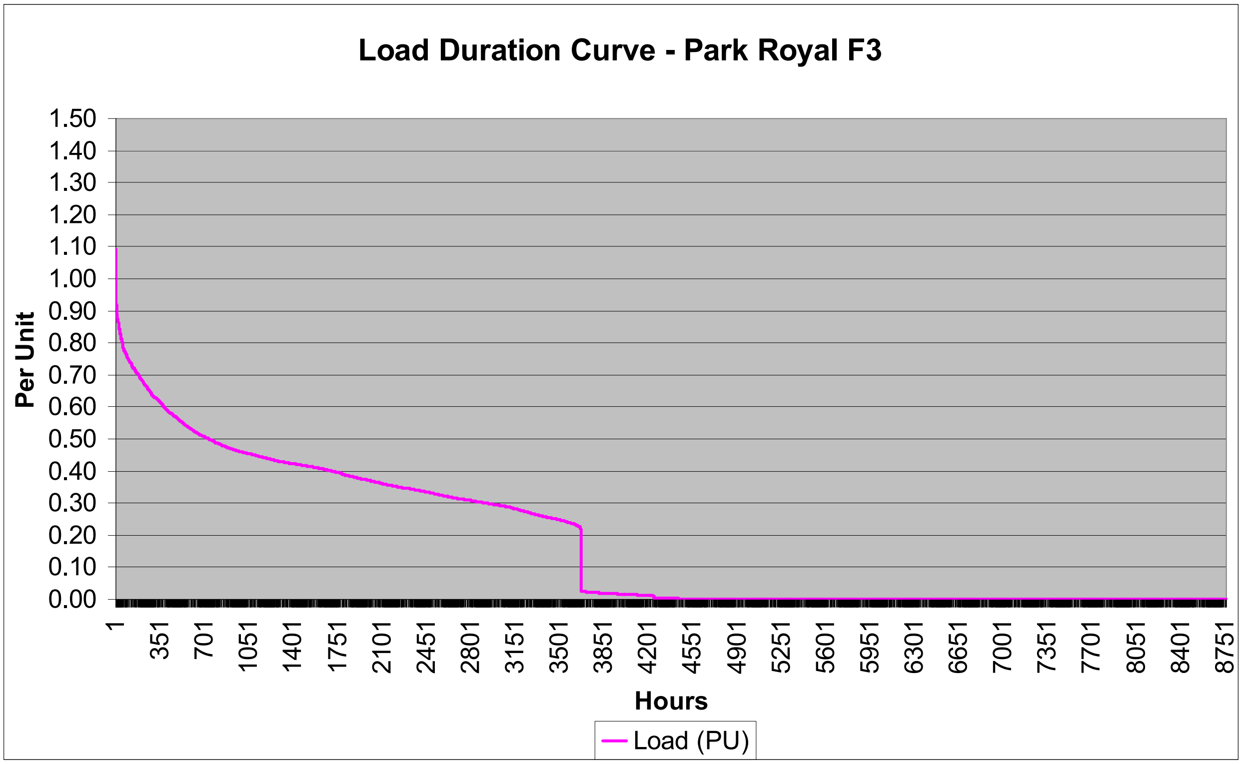
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Park Royal MS






Load Duration Curve - Park Royal F3
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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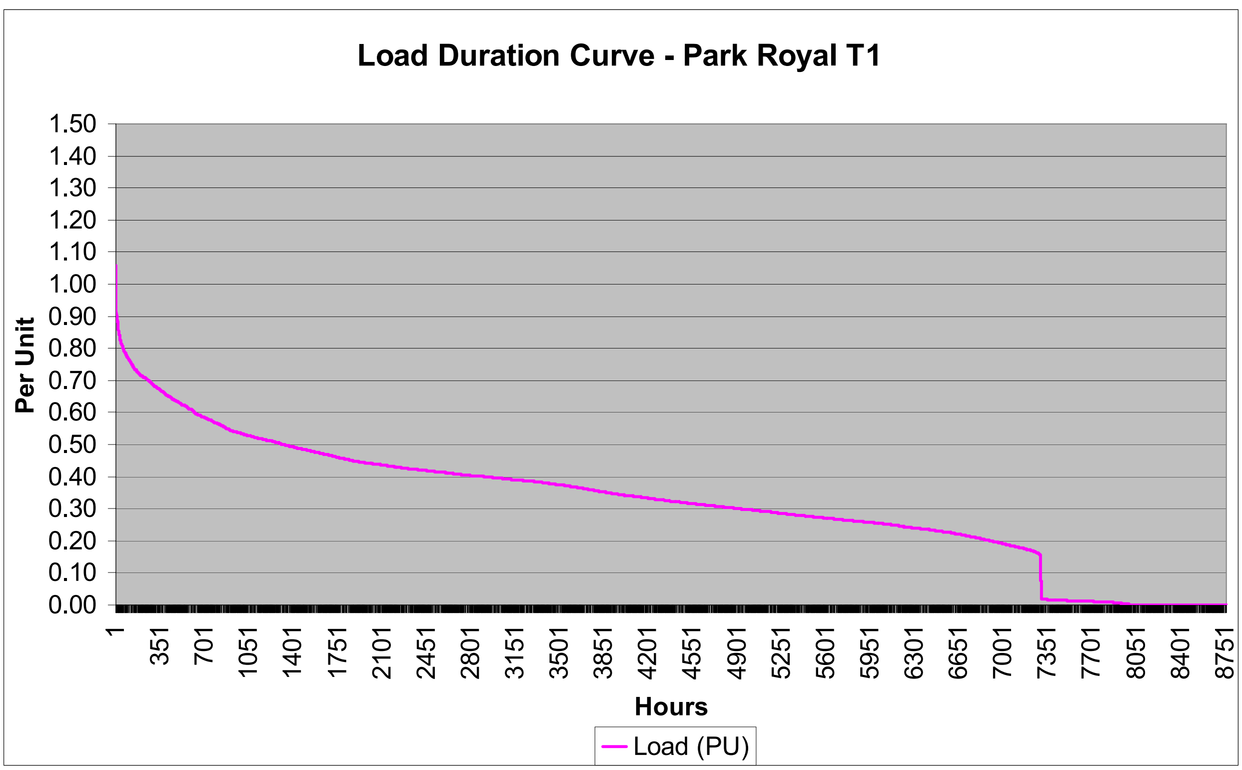
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Park Royal T1
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1.10
1.00
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
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3501
3851
4201
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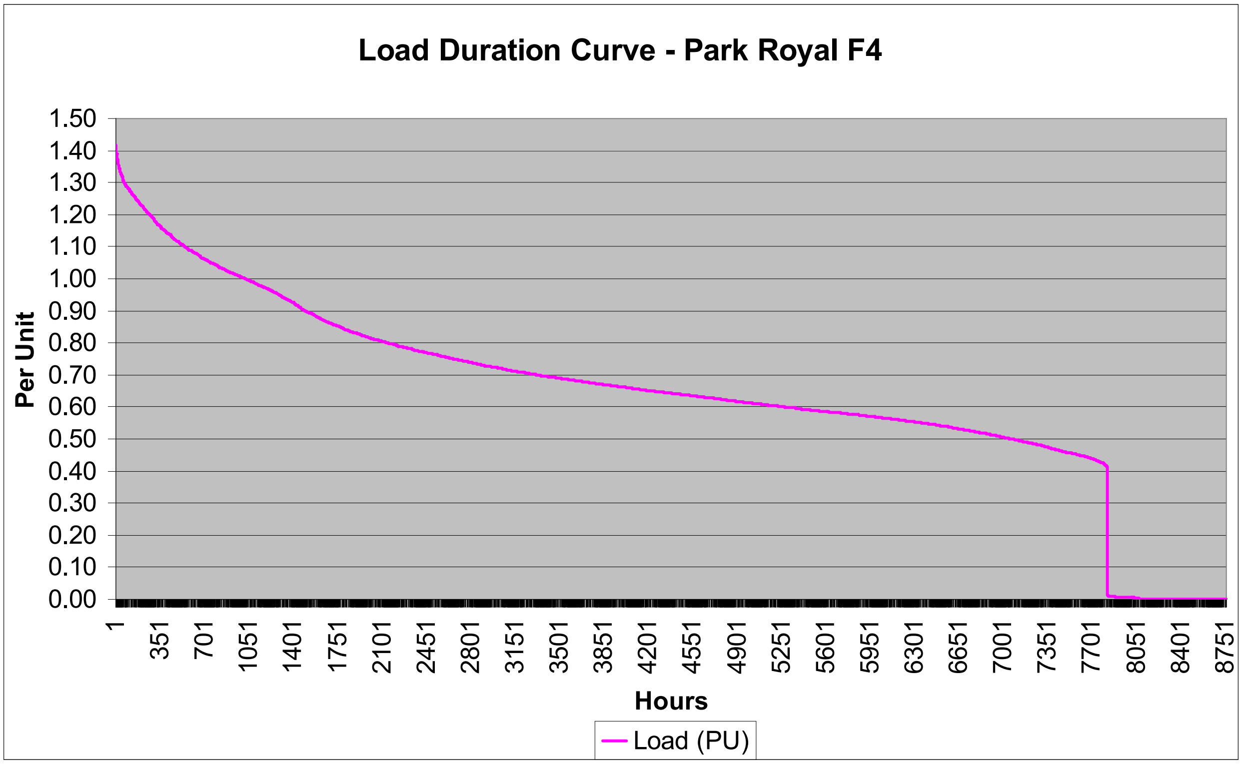
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Park Royal F4
Per Unit
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1.30
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6651
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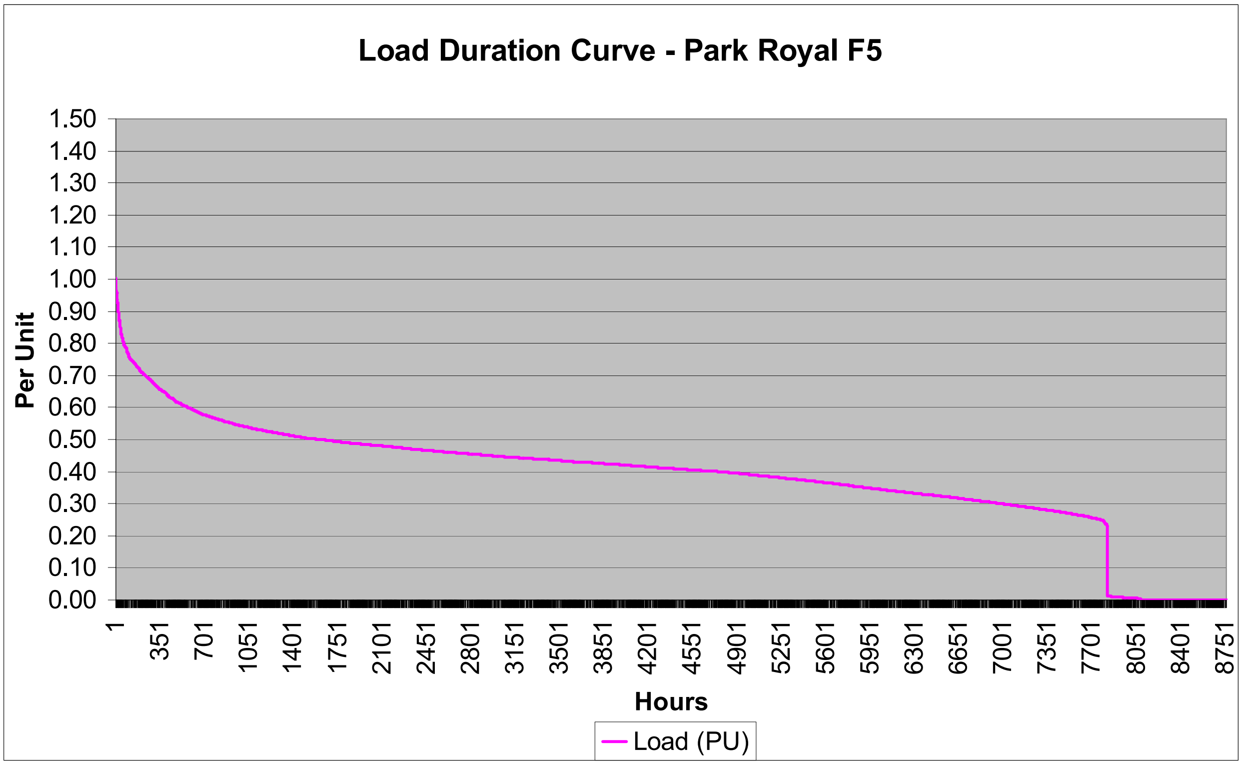
8401
8751
Hours
Load (PU)


Load Duration Curve - Park Royal F5
Per Unit
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0.70
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0.50
0.40
0.30
0.20
0.10
0.00
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351
701
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4201
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6651
7001
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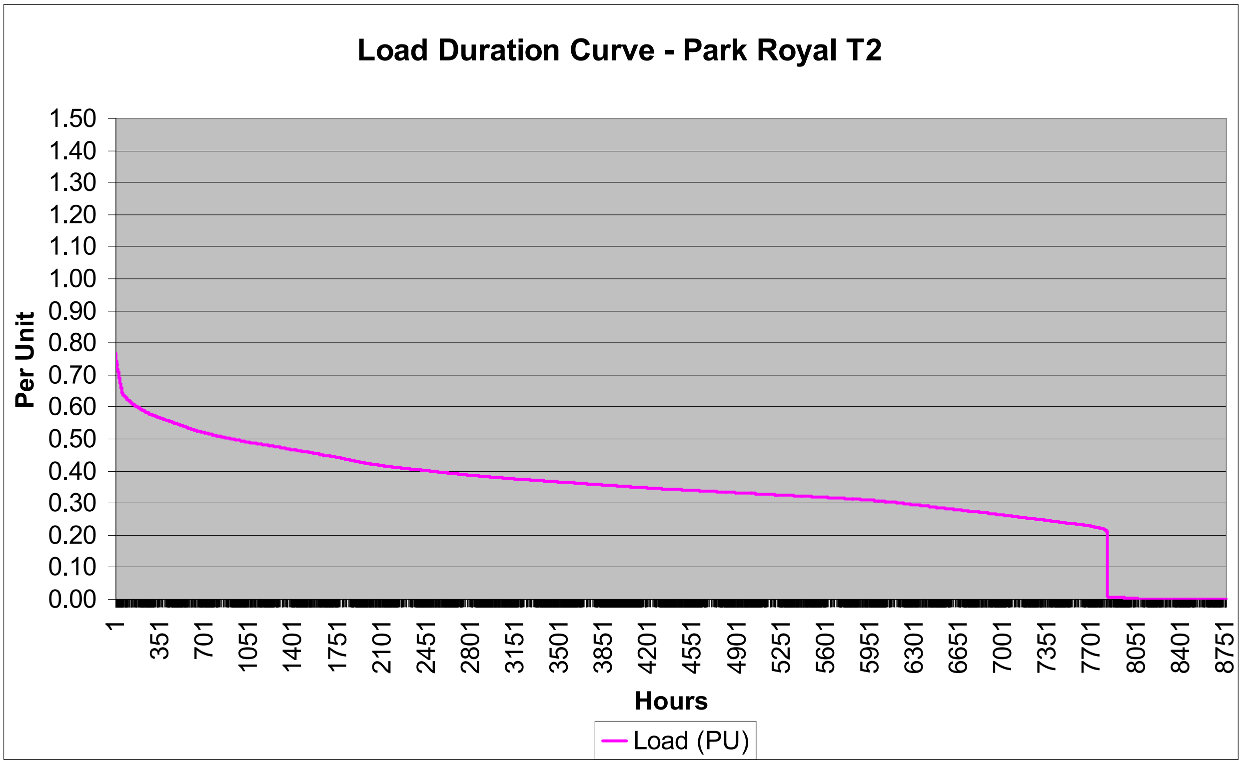
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Park Royal T2
Per Unit
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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2101
2451
2801
3151
3501
3851
4201
4551
4901
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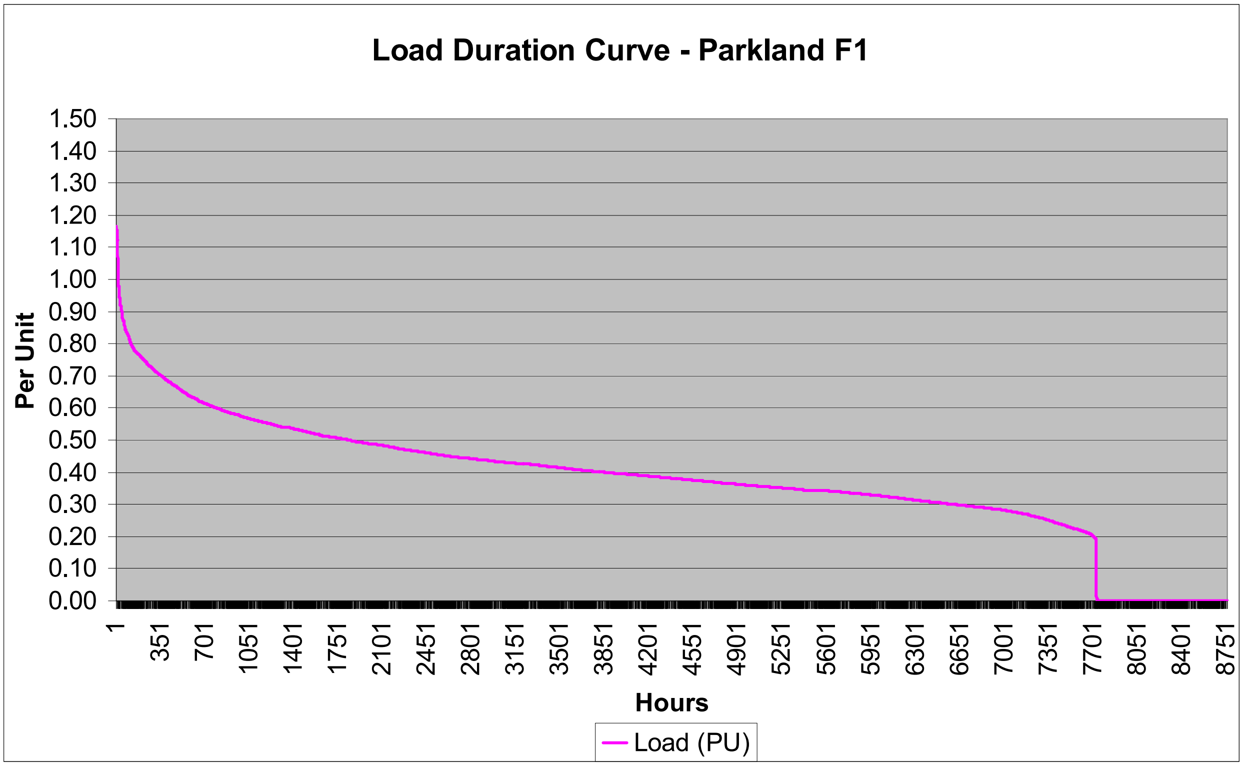
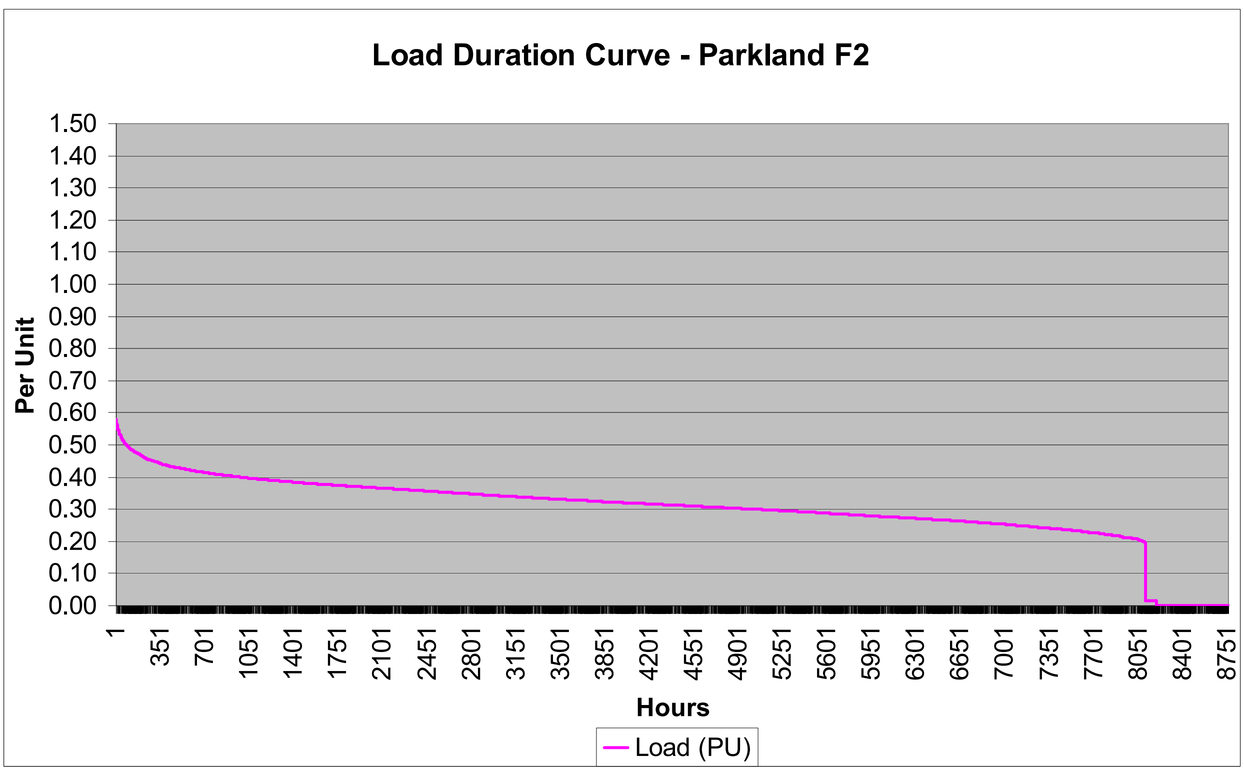
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

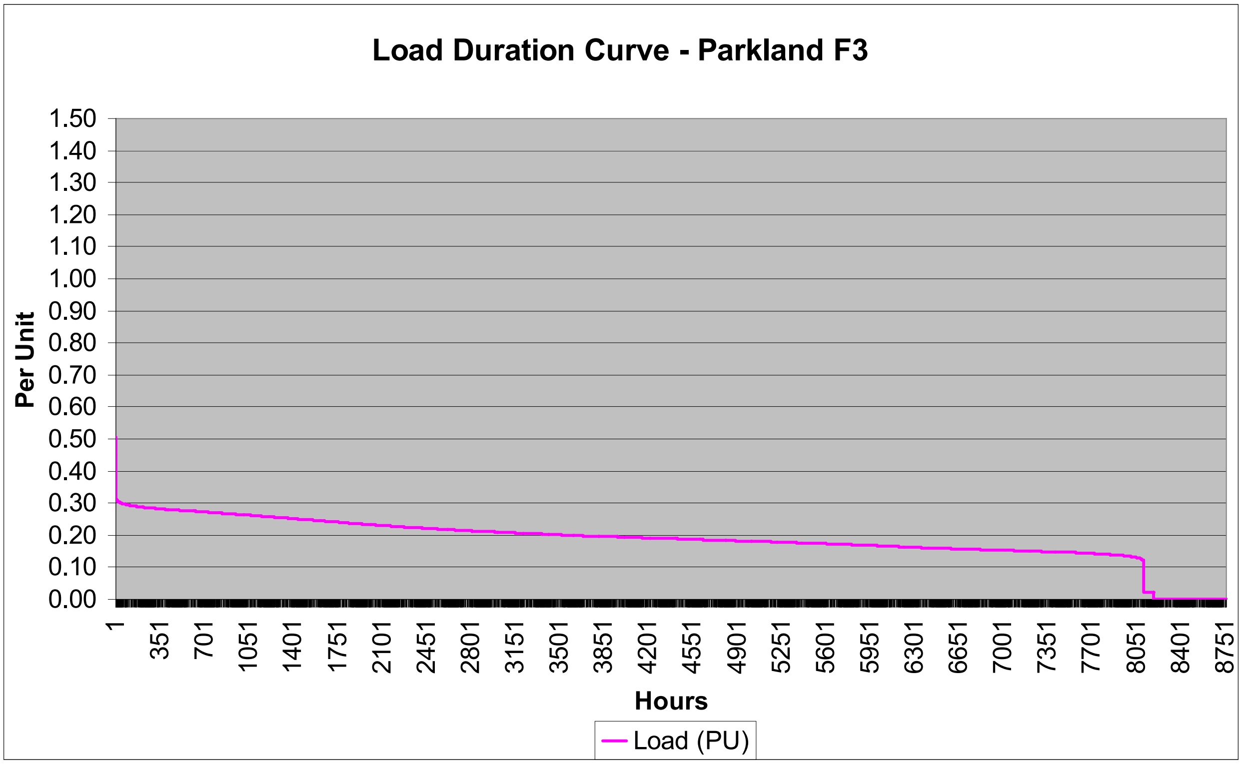
Parkland MS

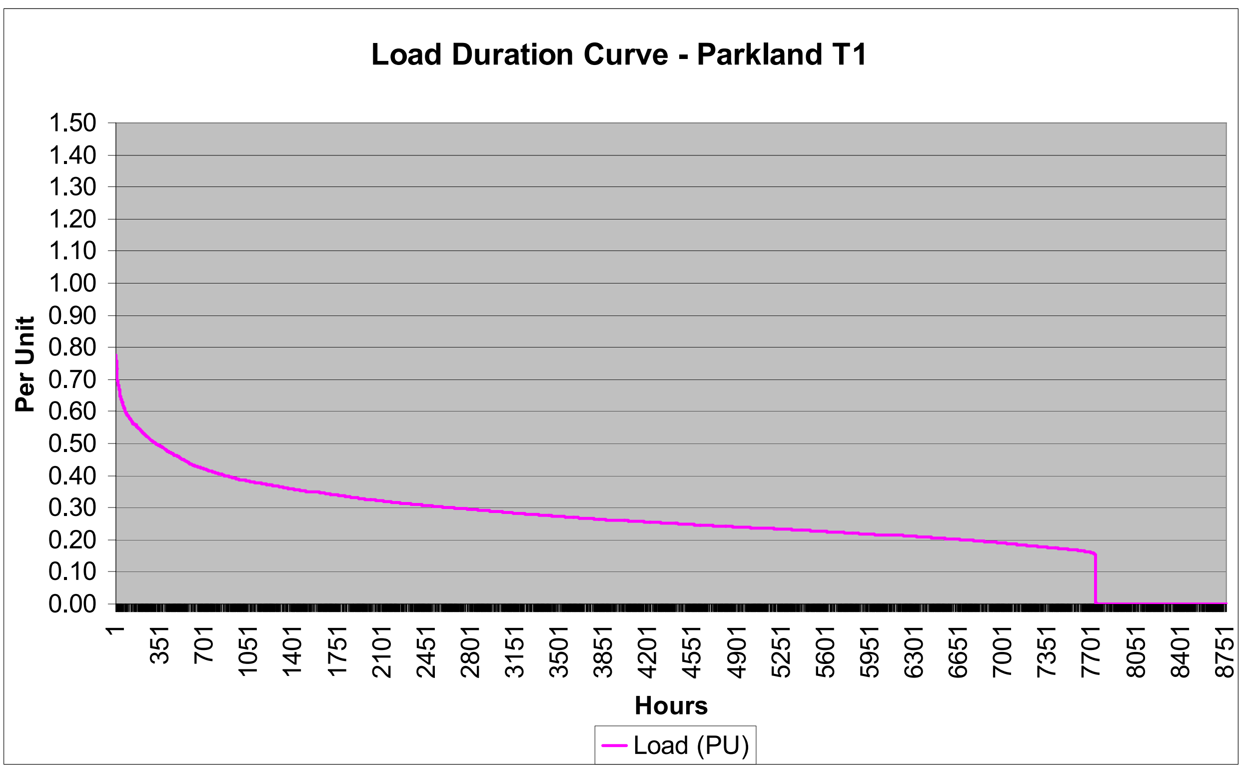


Load Duration Curve - Parkland F1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

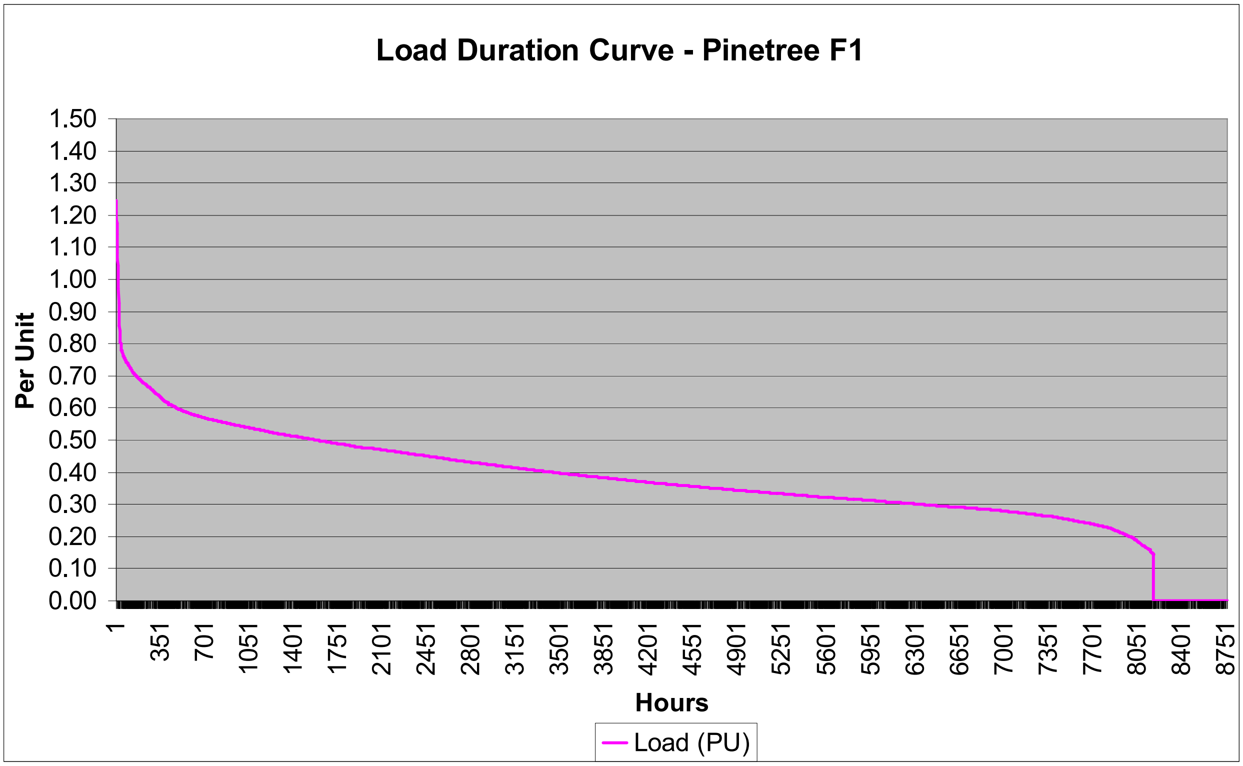


Load Duration Curve - Parkland F2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

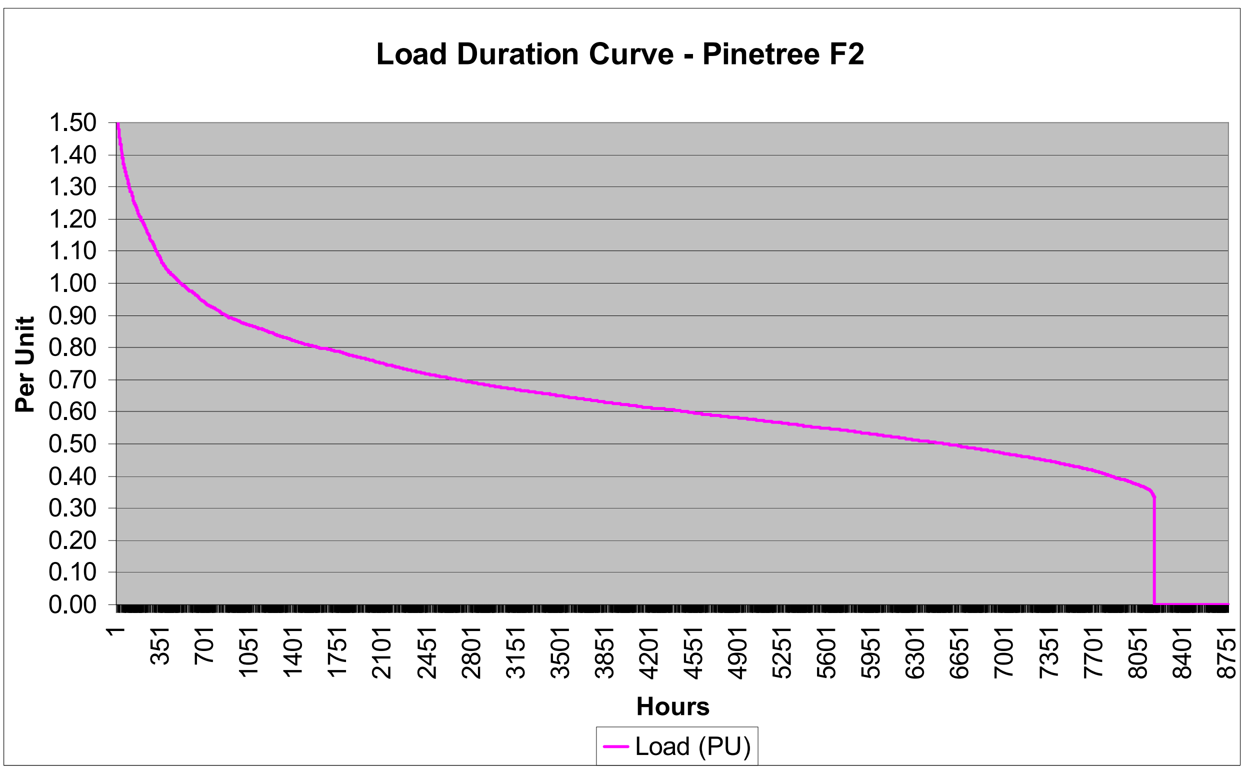

Load Duration Curve - Parkland F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Parkland T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

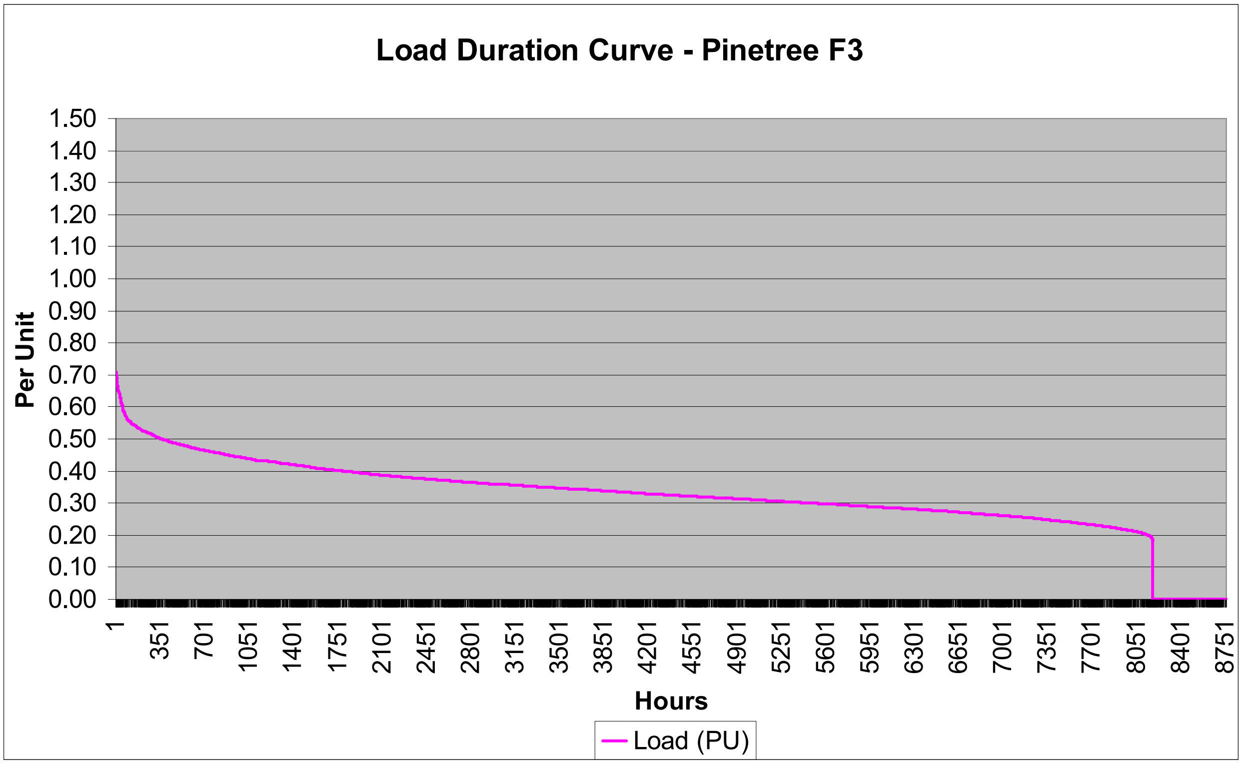
Pinetree MS



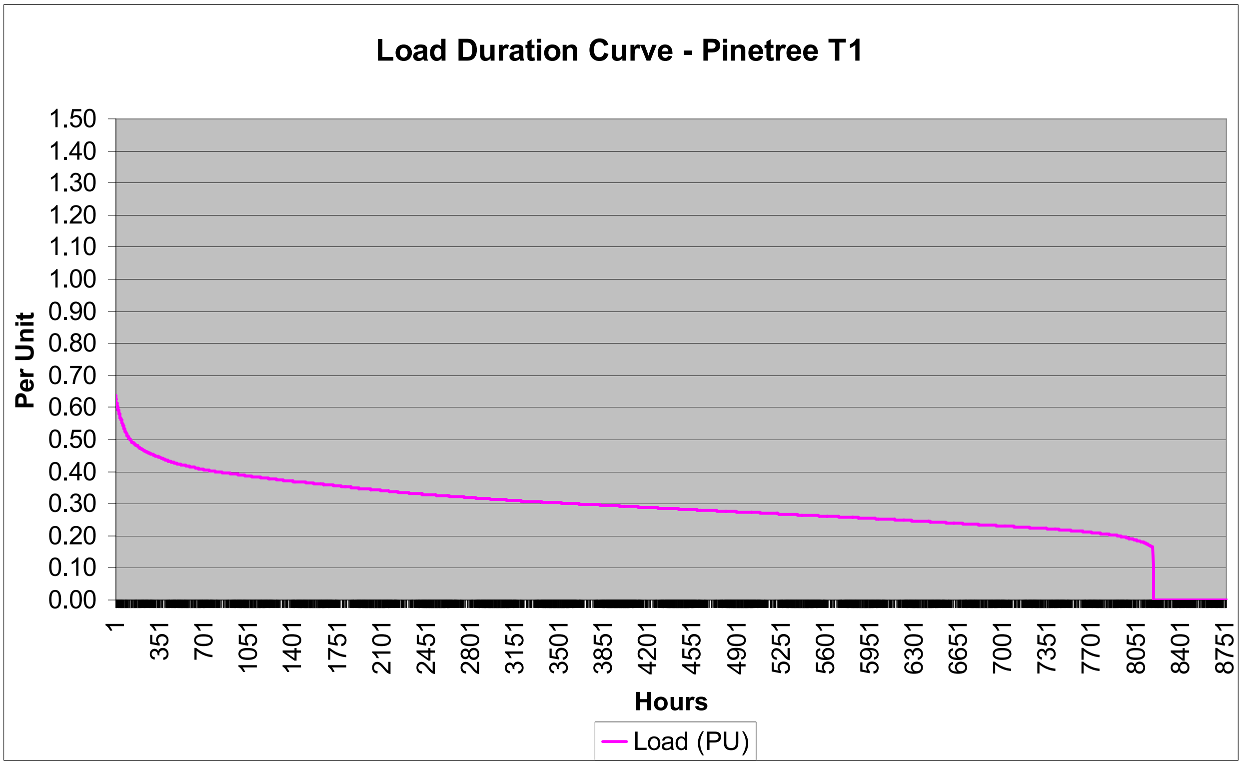
Load Duration Curve - Pinetree F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Pinetree F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

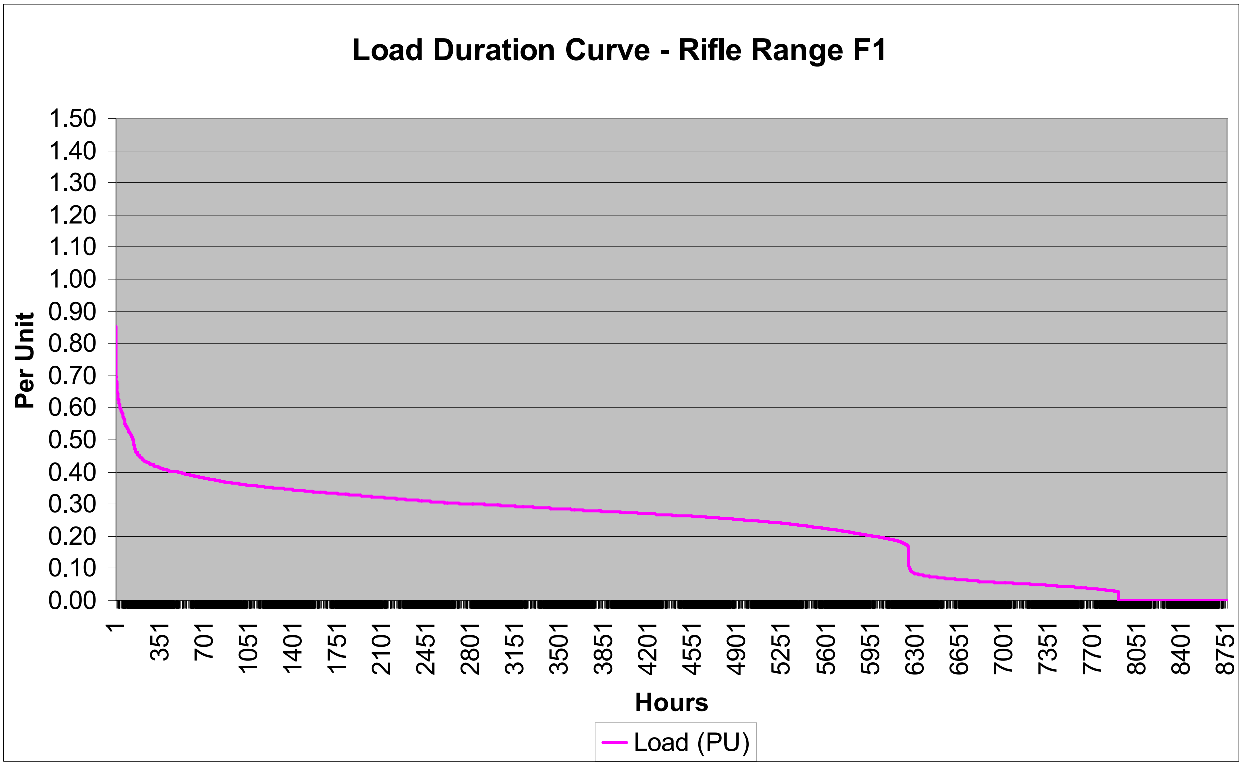


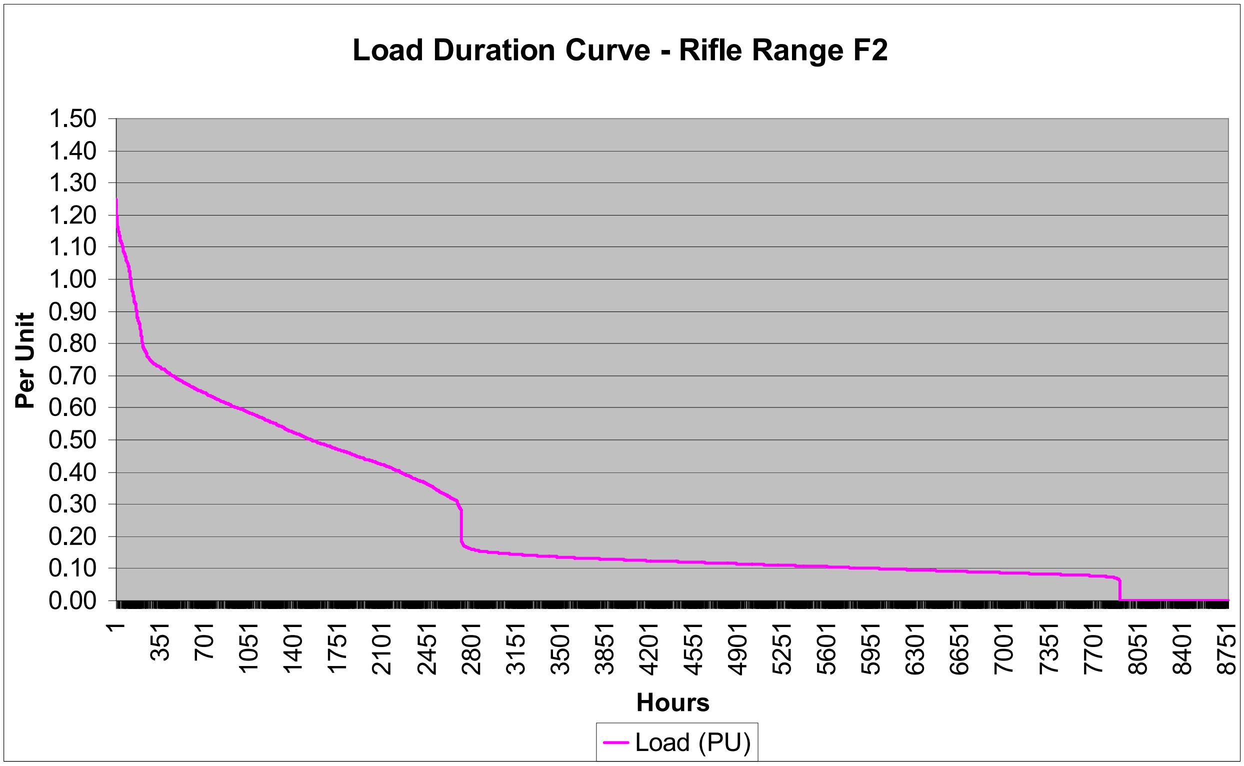
Load Duration Curve - Pinetree F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

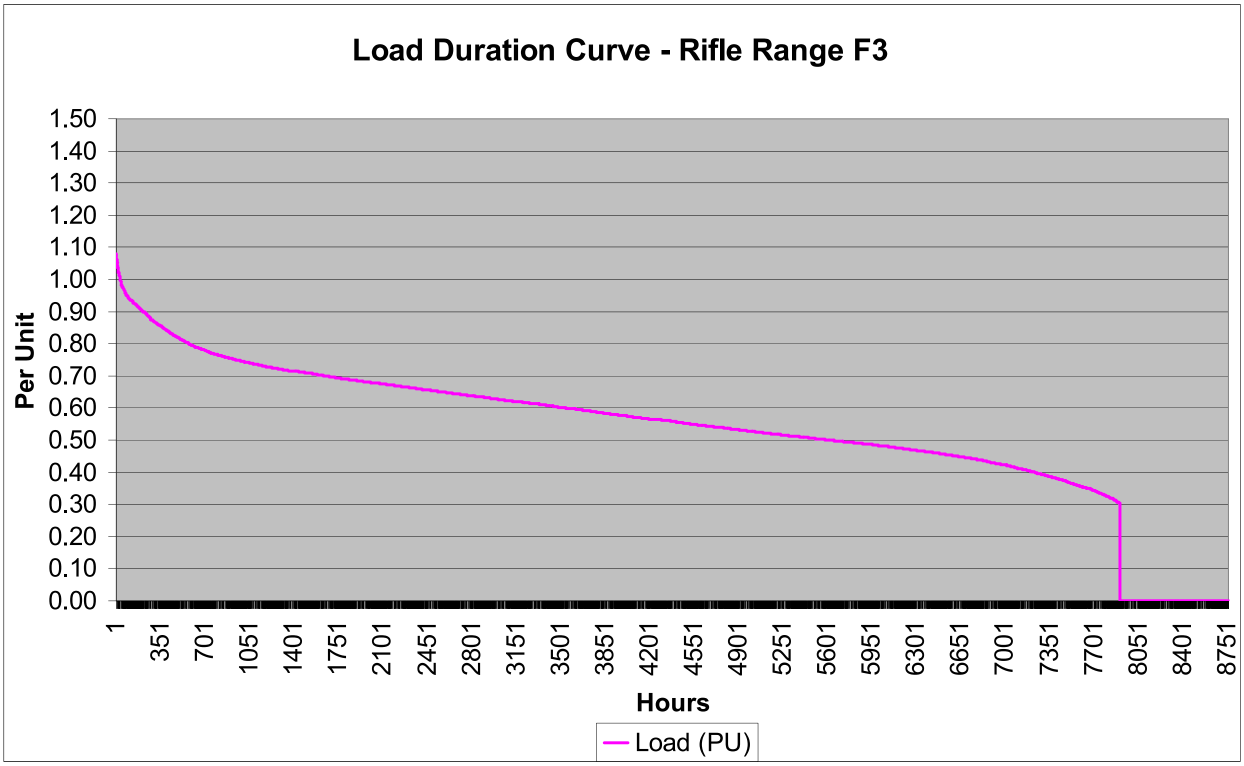


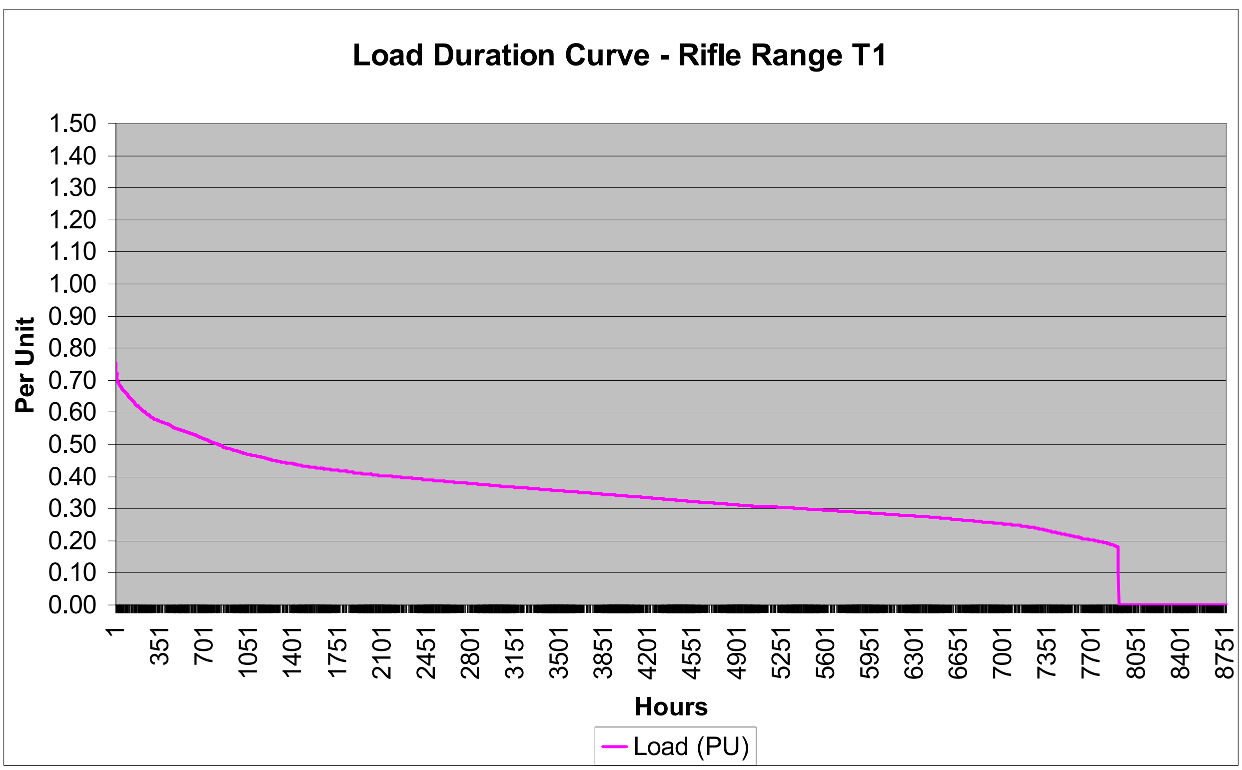
Load Duration Curve - Pinetree T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

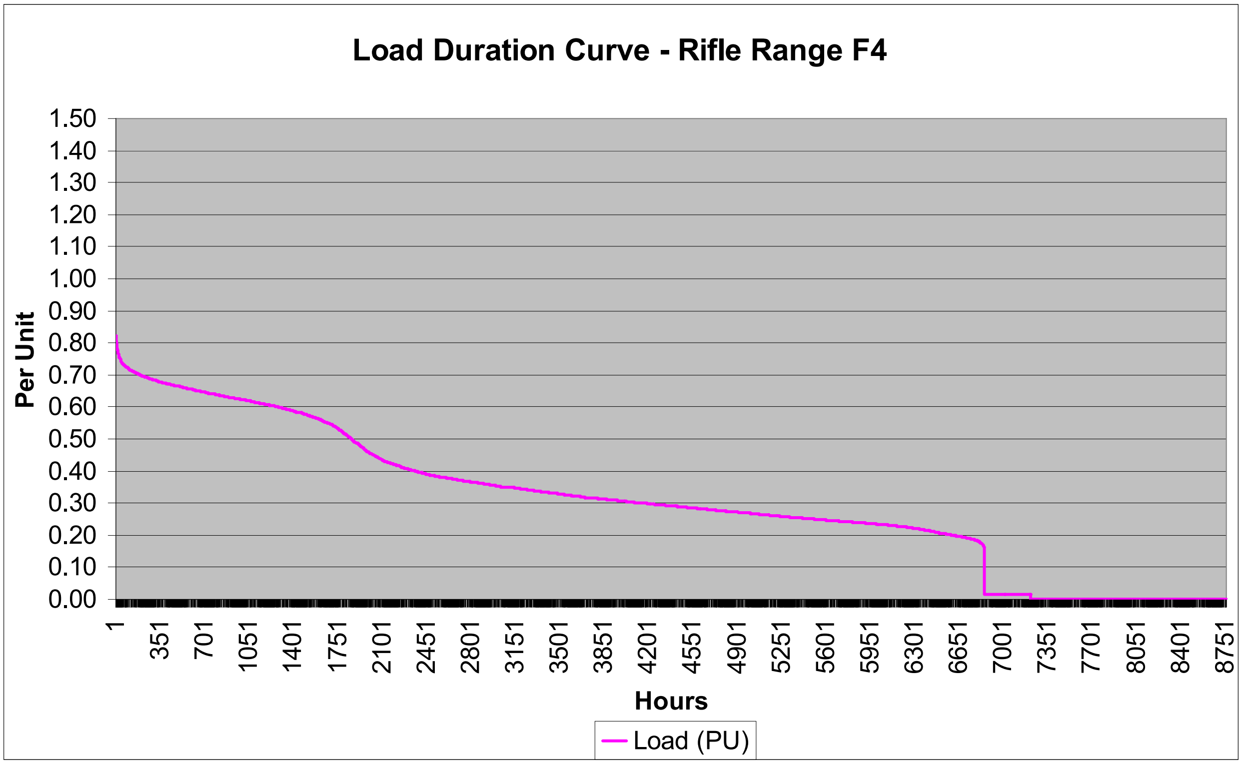
Rifle Range MS

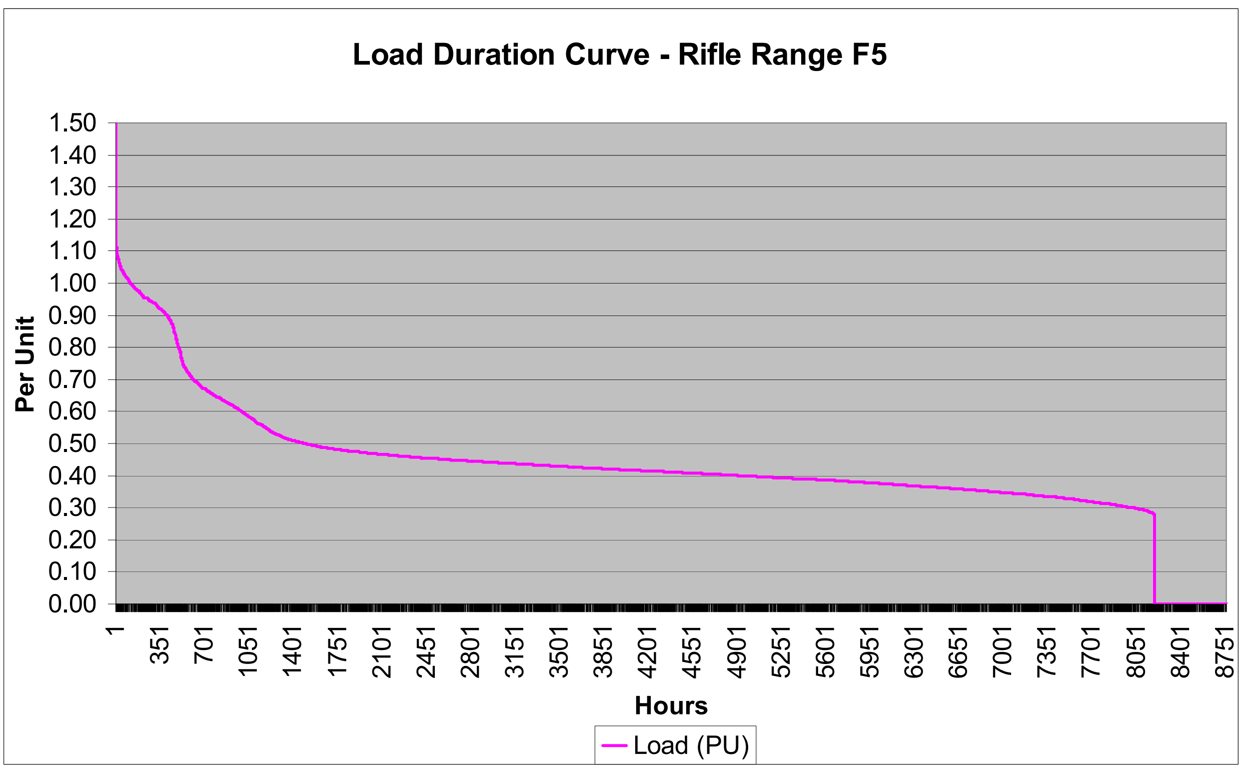


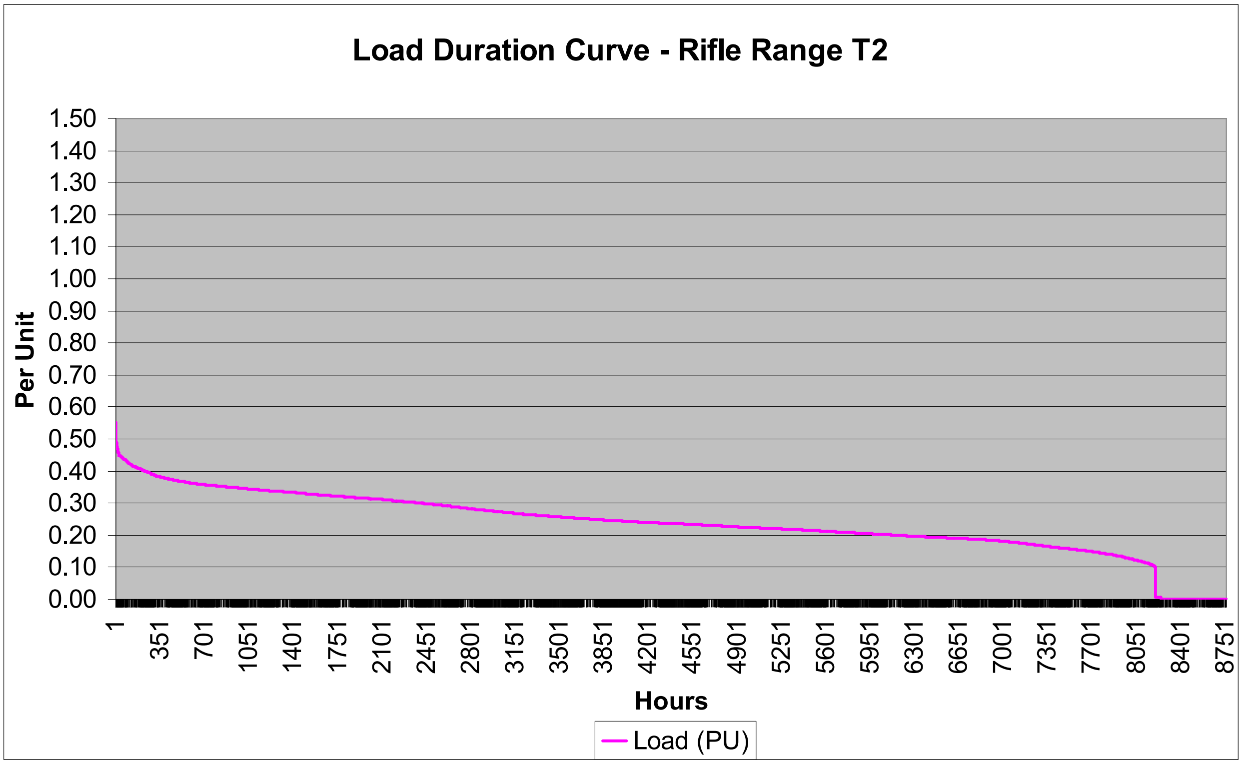



Load Duration Curve - Rifle Range F3
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rifle Range T1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

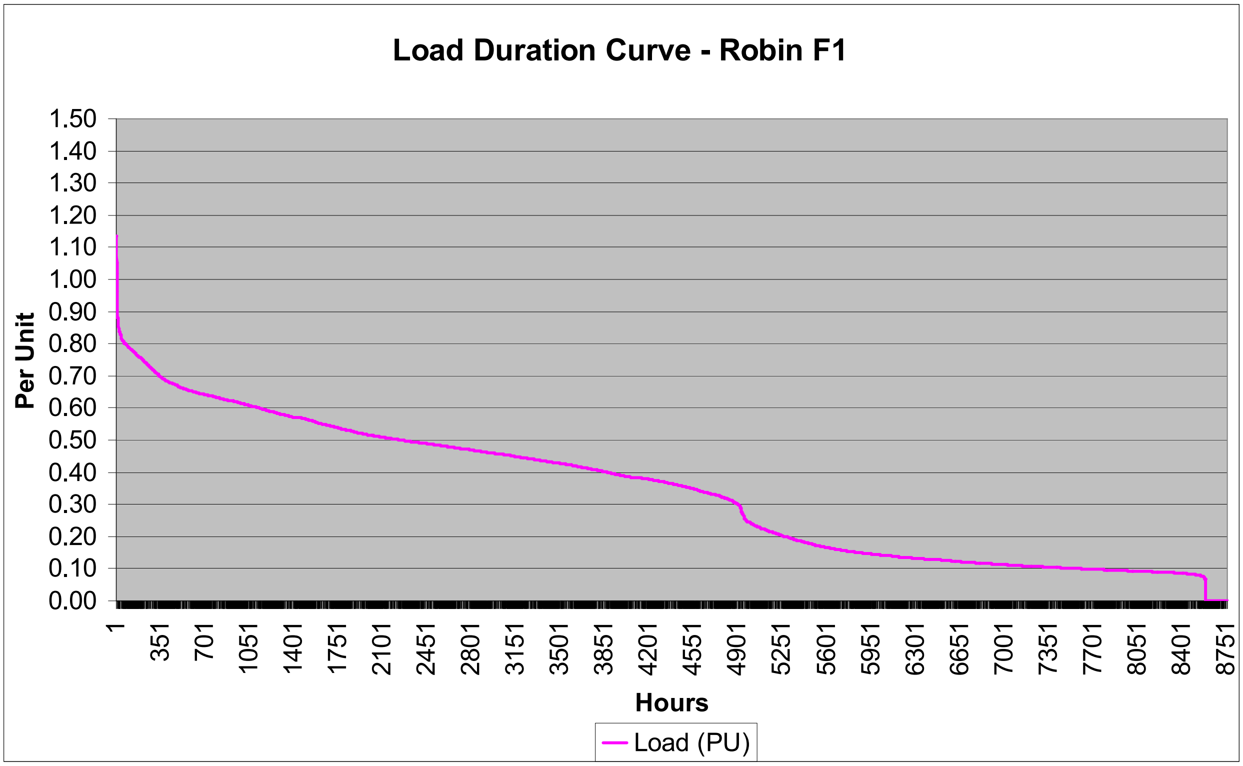

Load Duration Curve - Rifle Range F4
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rifle Range F5
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

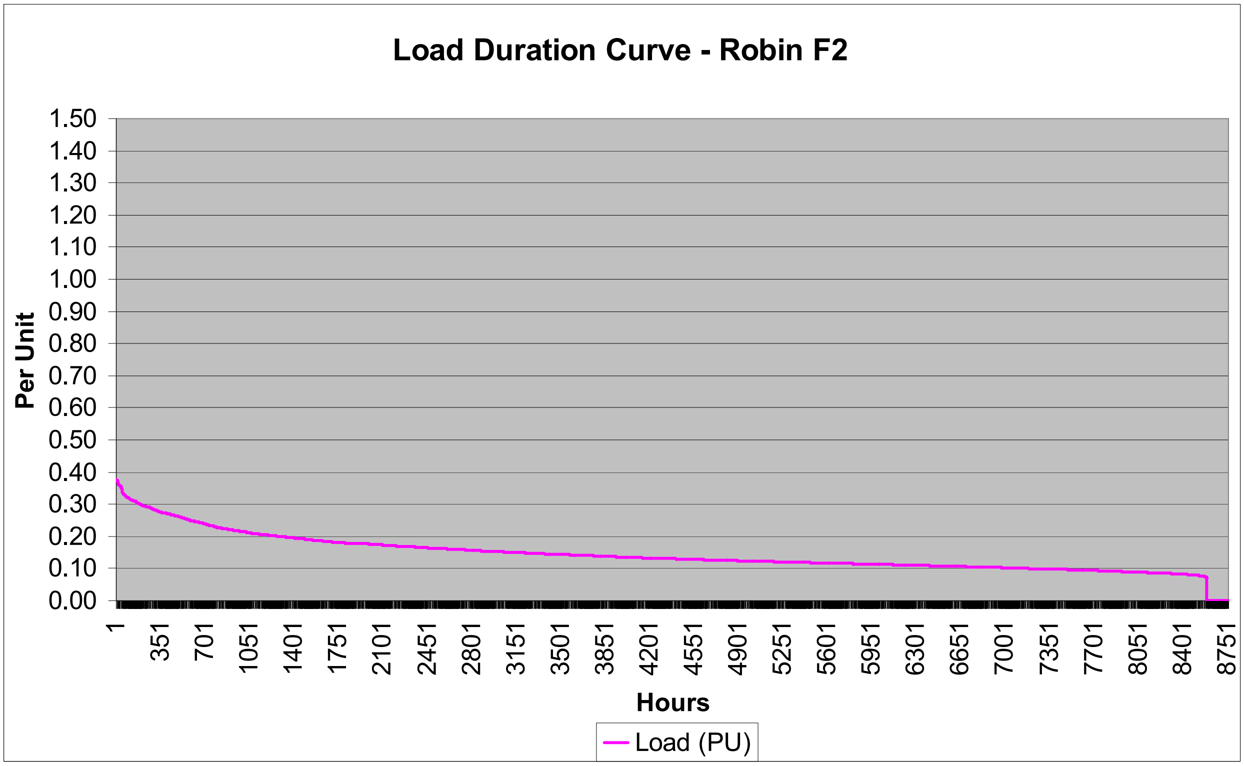


Load Duration Curve - Rifle Range T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

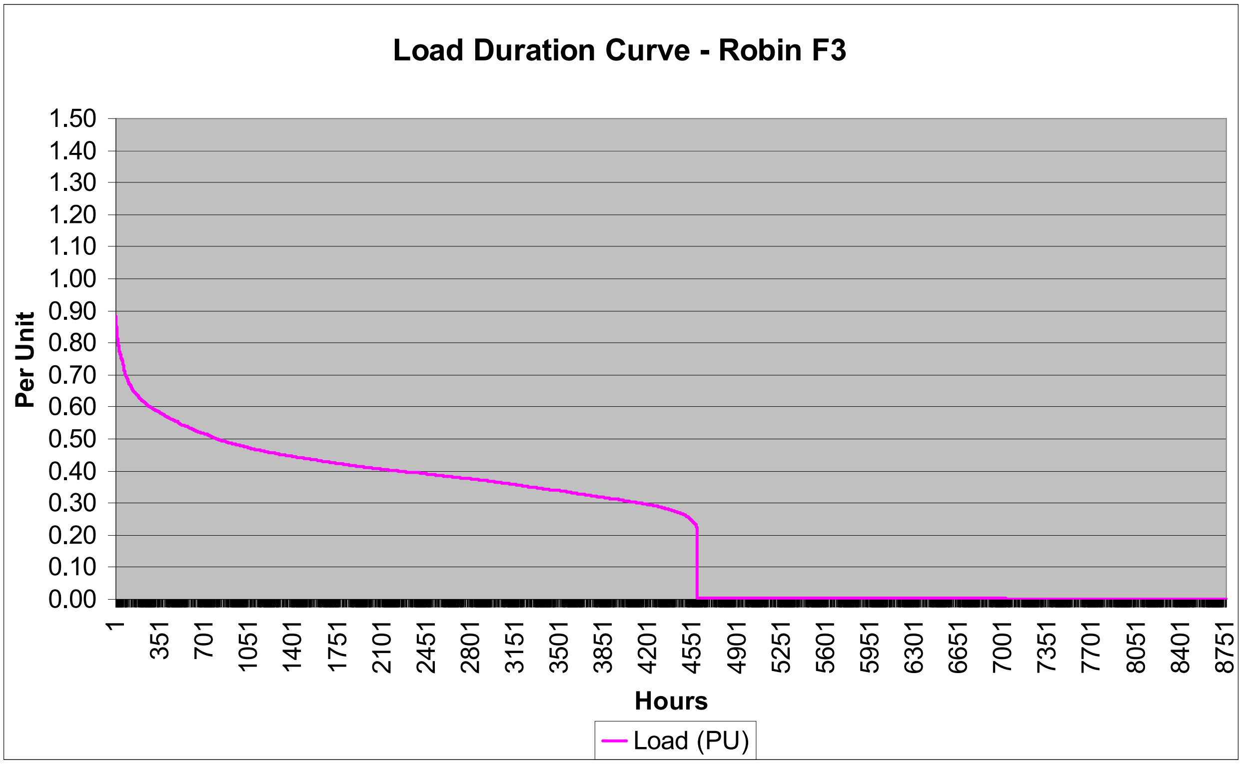
Robin MS



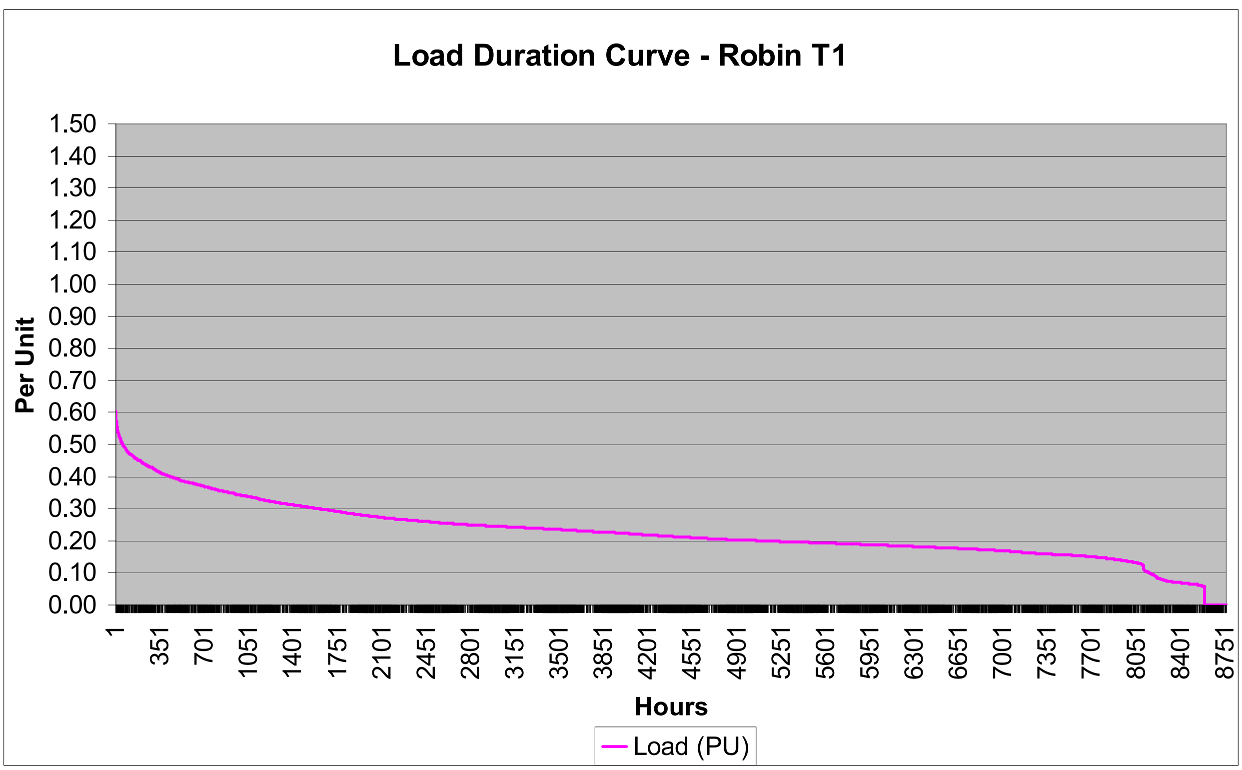
Load Duration Curve - Robin F1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Robin F2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

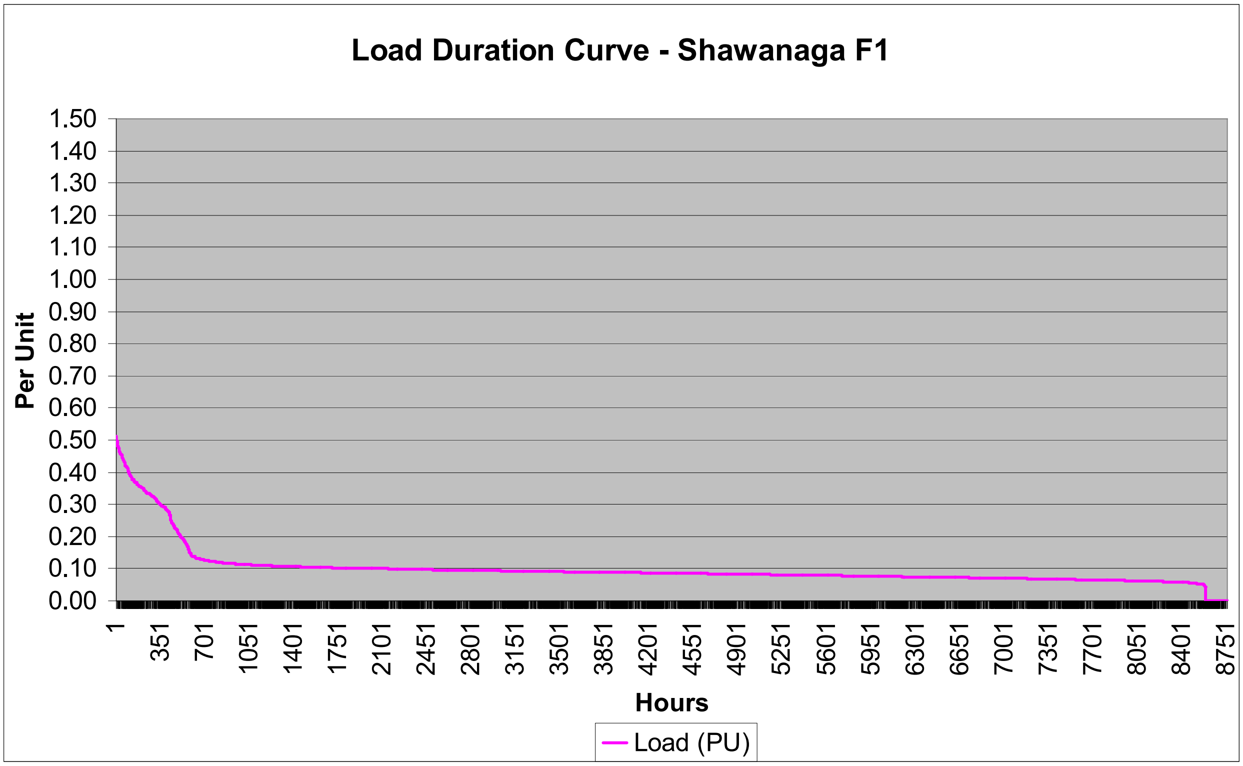


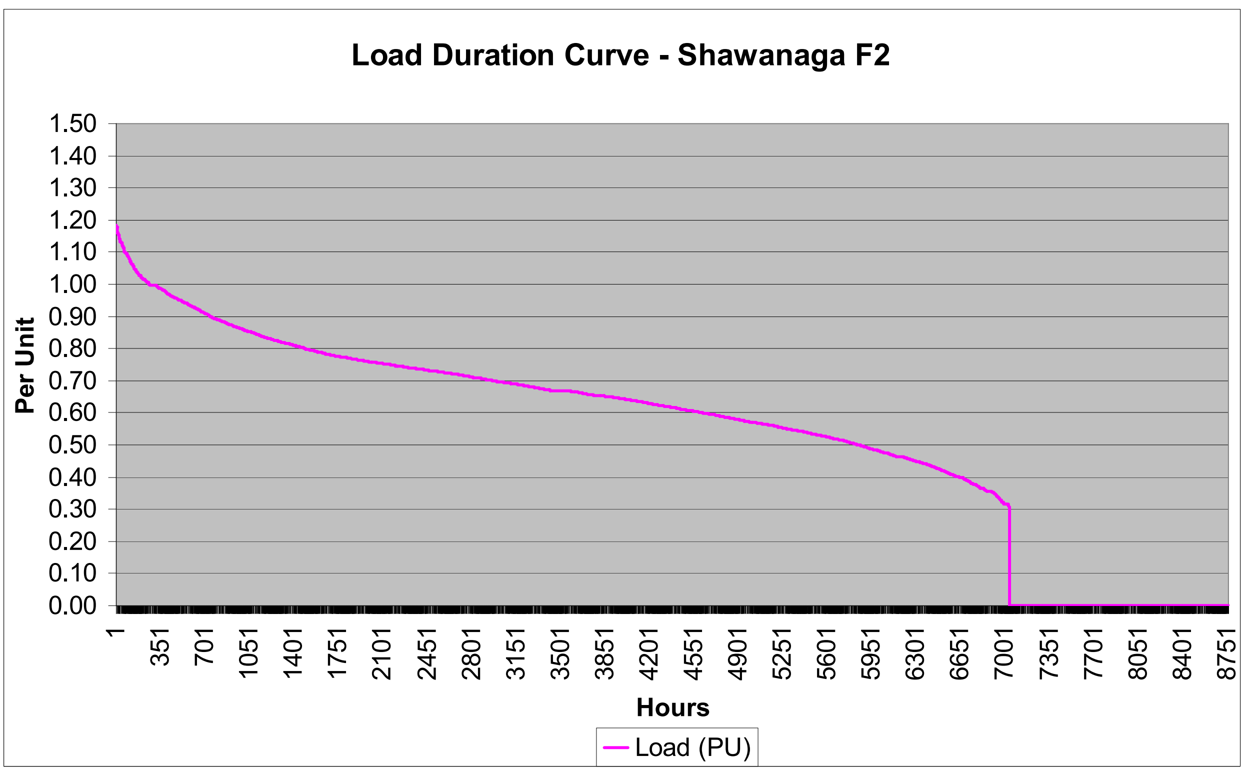
Load Duration Curve - Robin F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

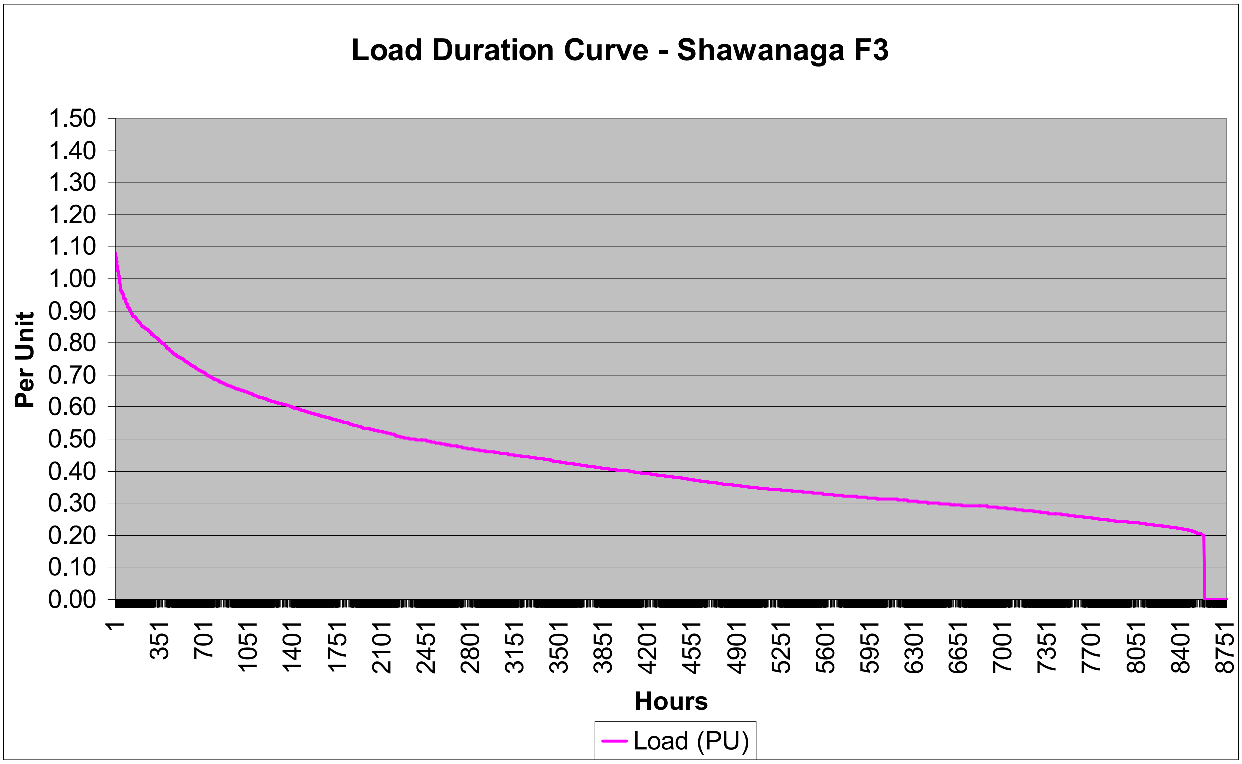


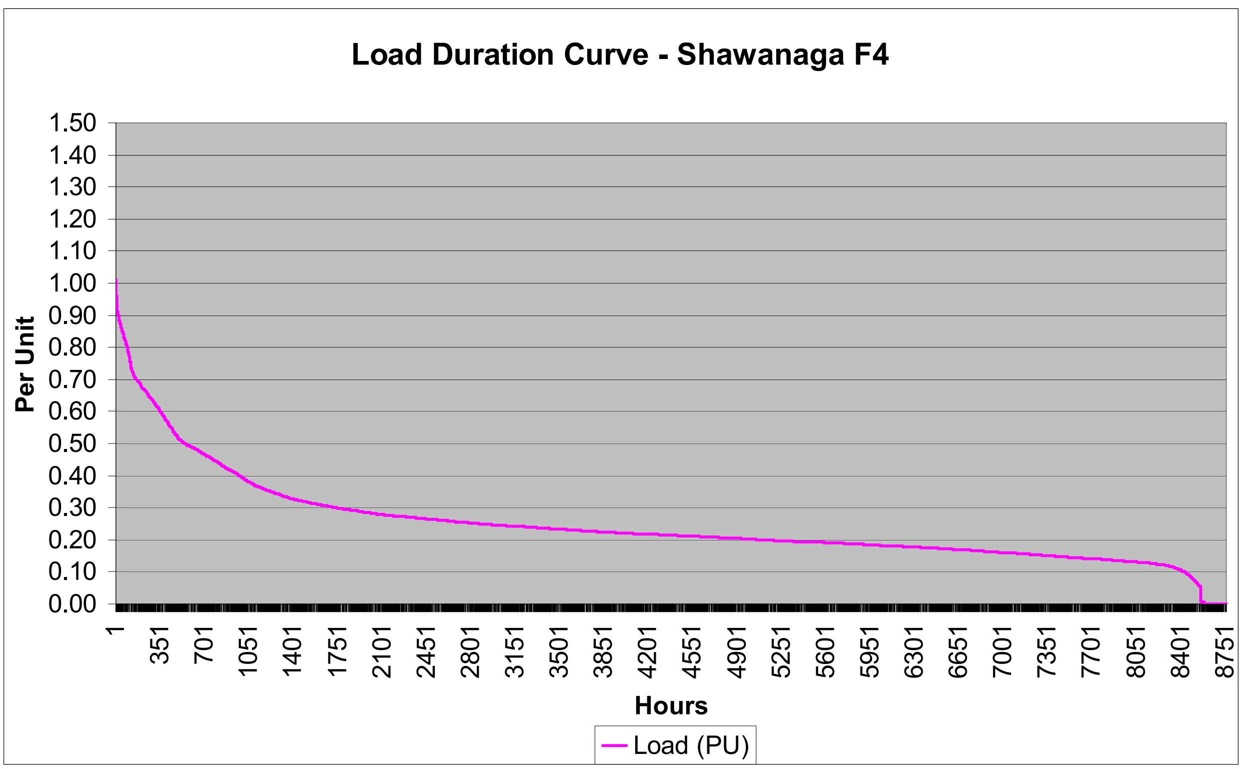
Load Duration Curve - Robin T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

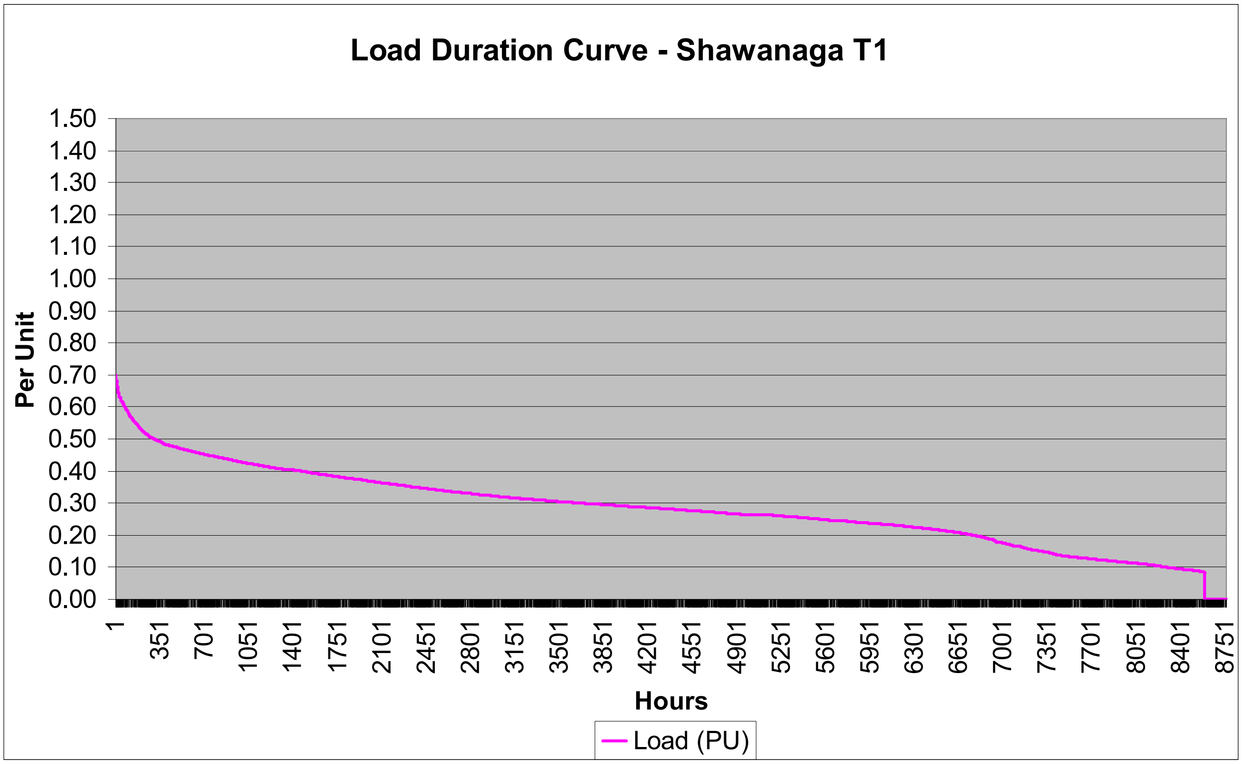
Shawanaga MS



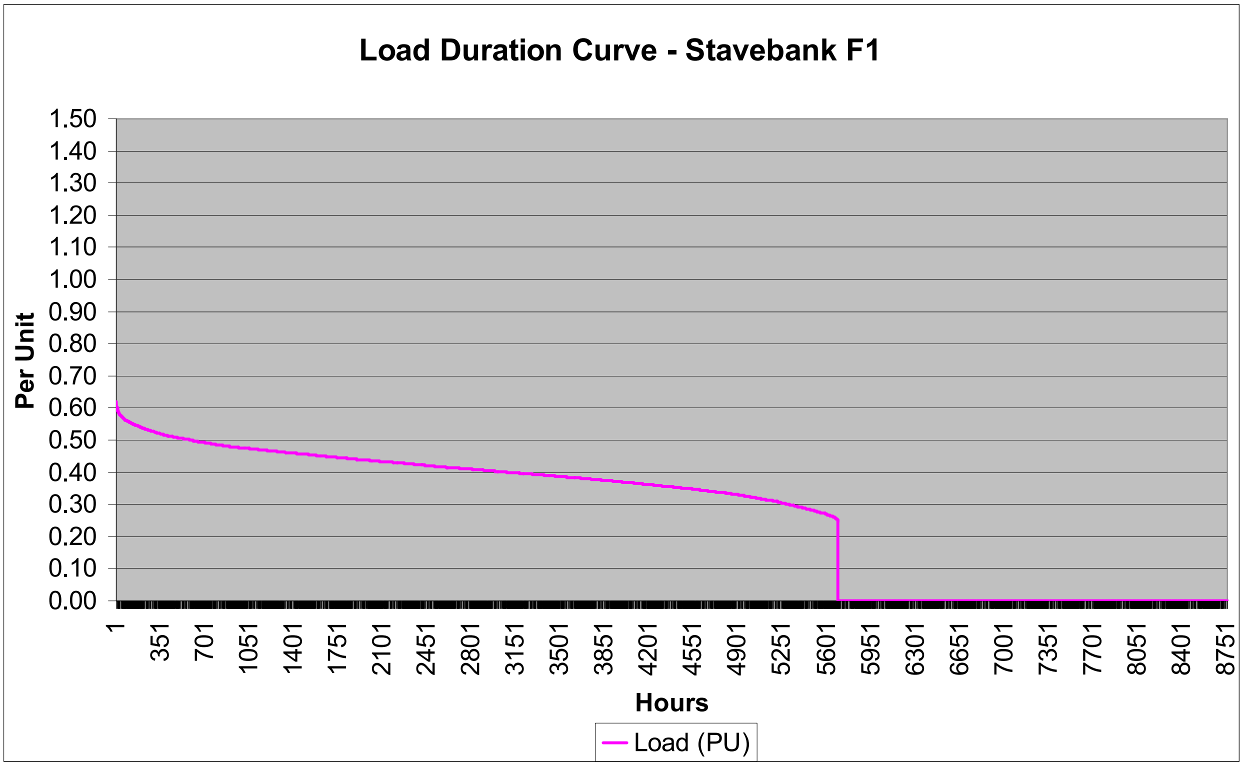


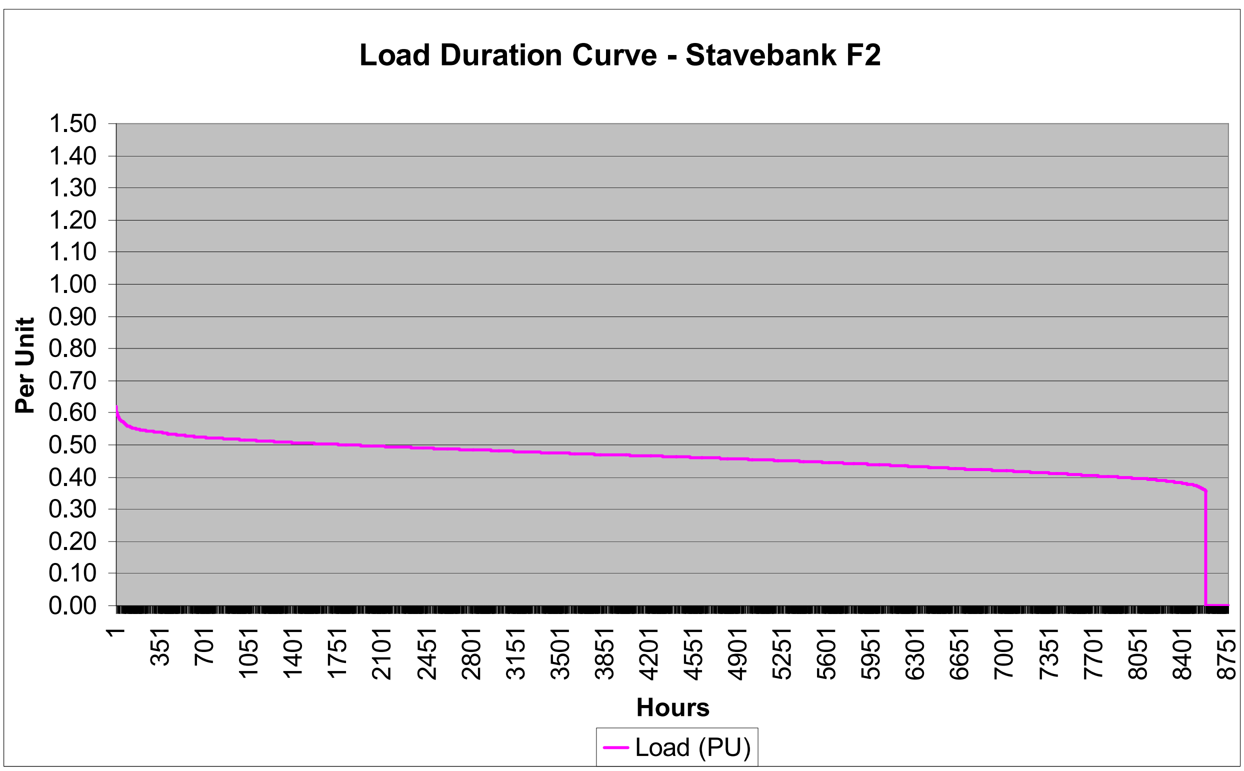

Load Duration Curve - Shawanaga F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

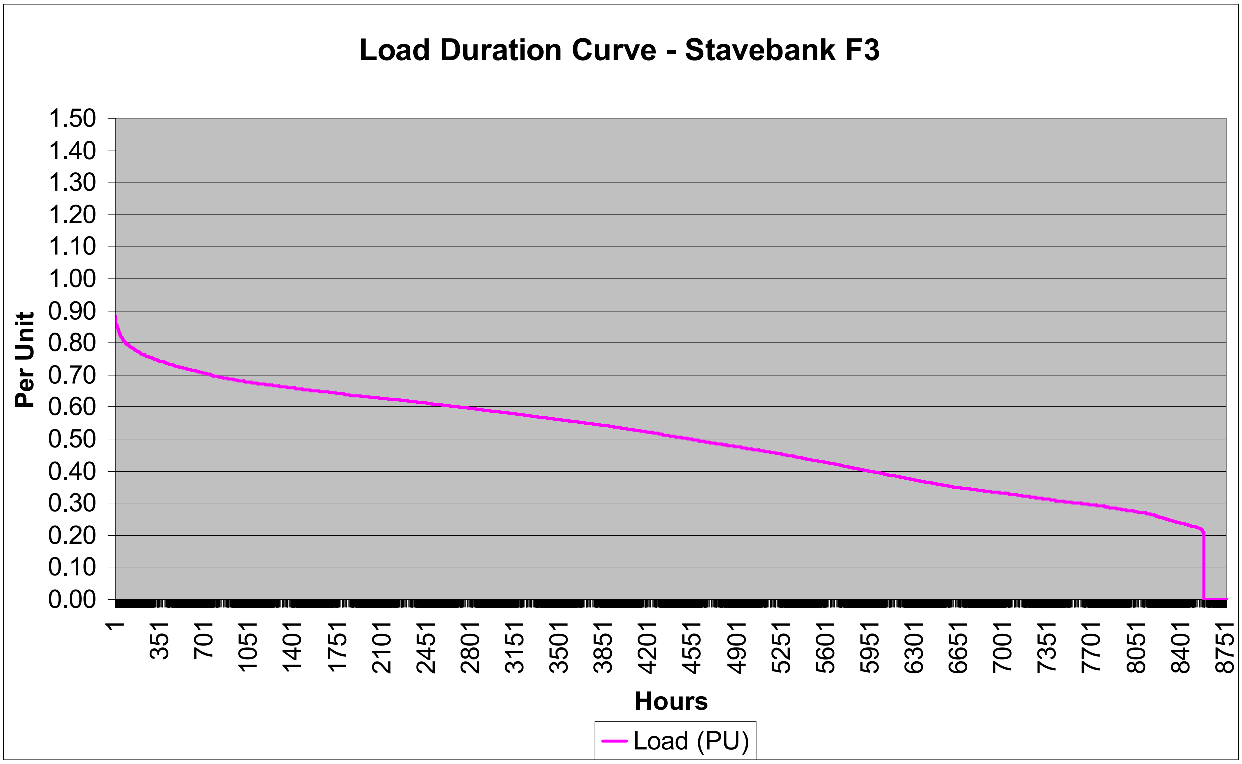

Load Duration Curve - Shawanaga F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawanaga T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

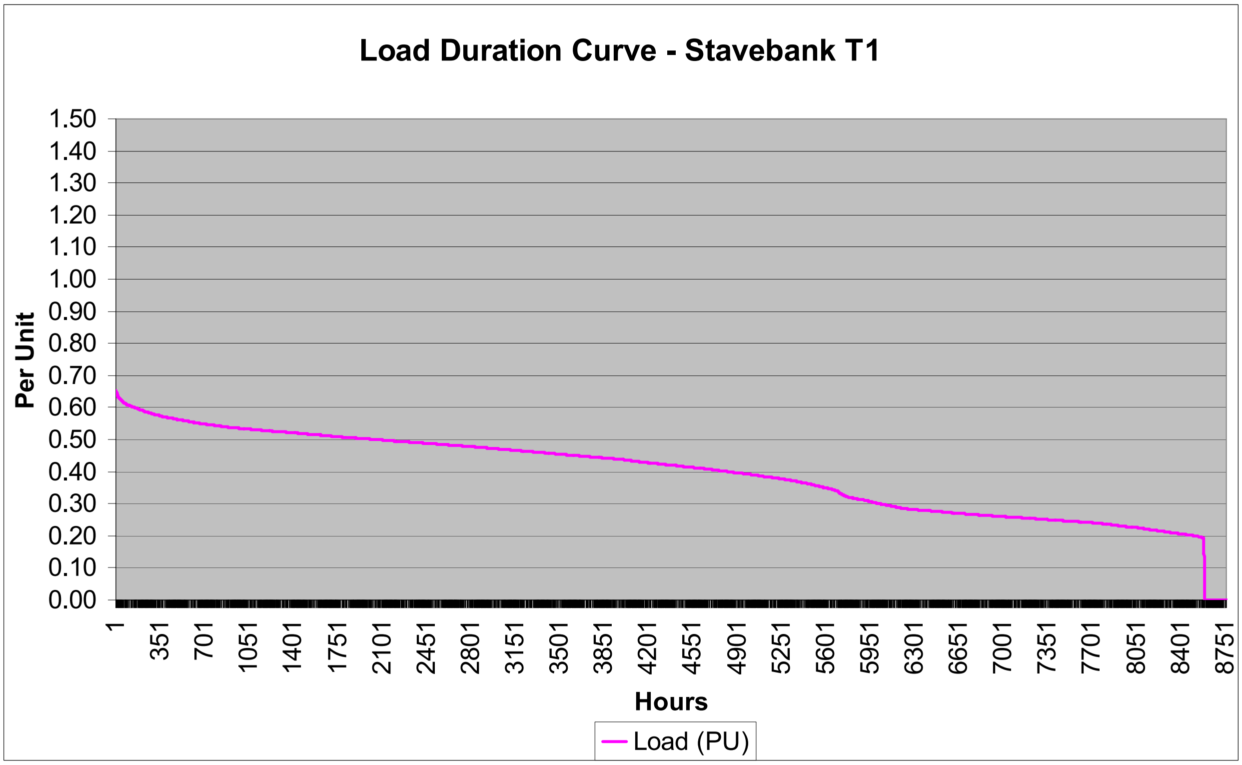
Stavebank MS





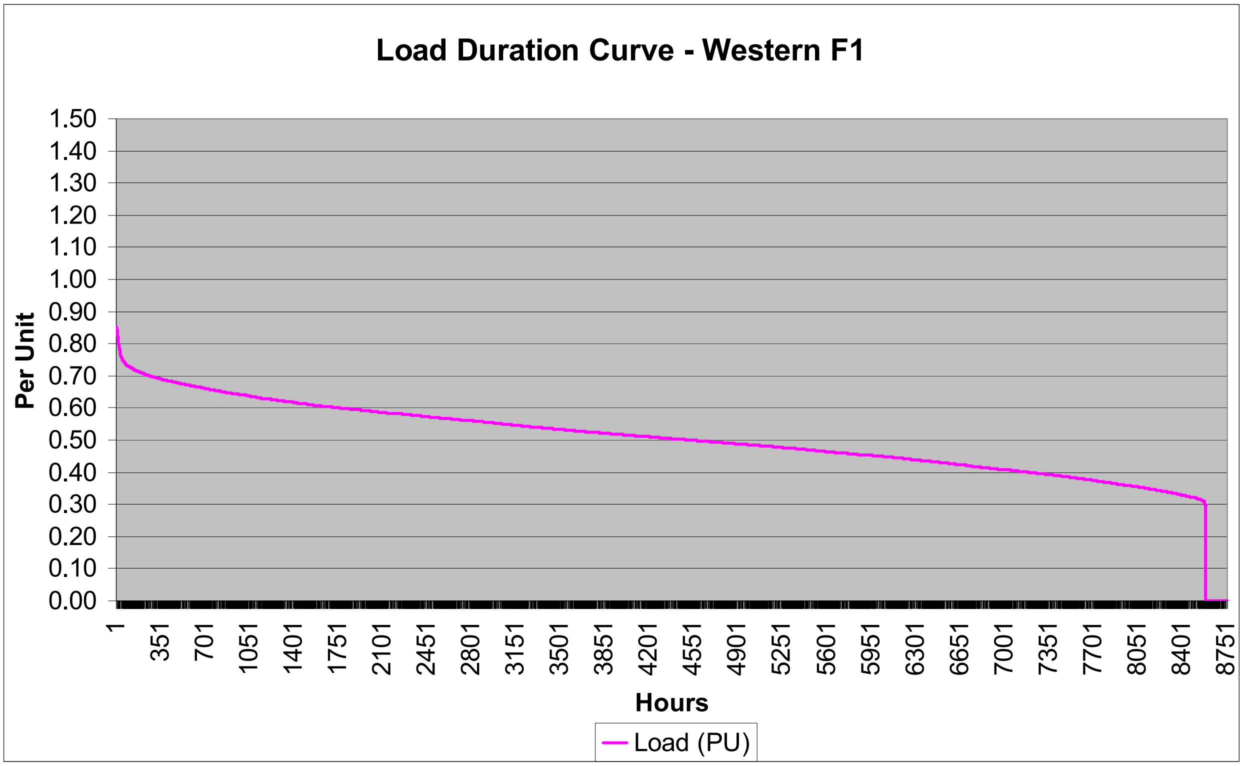


Load Duration Curve - Stavebank F3
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Stavebank T1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Western MS



Load Duration Curve - Western F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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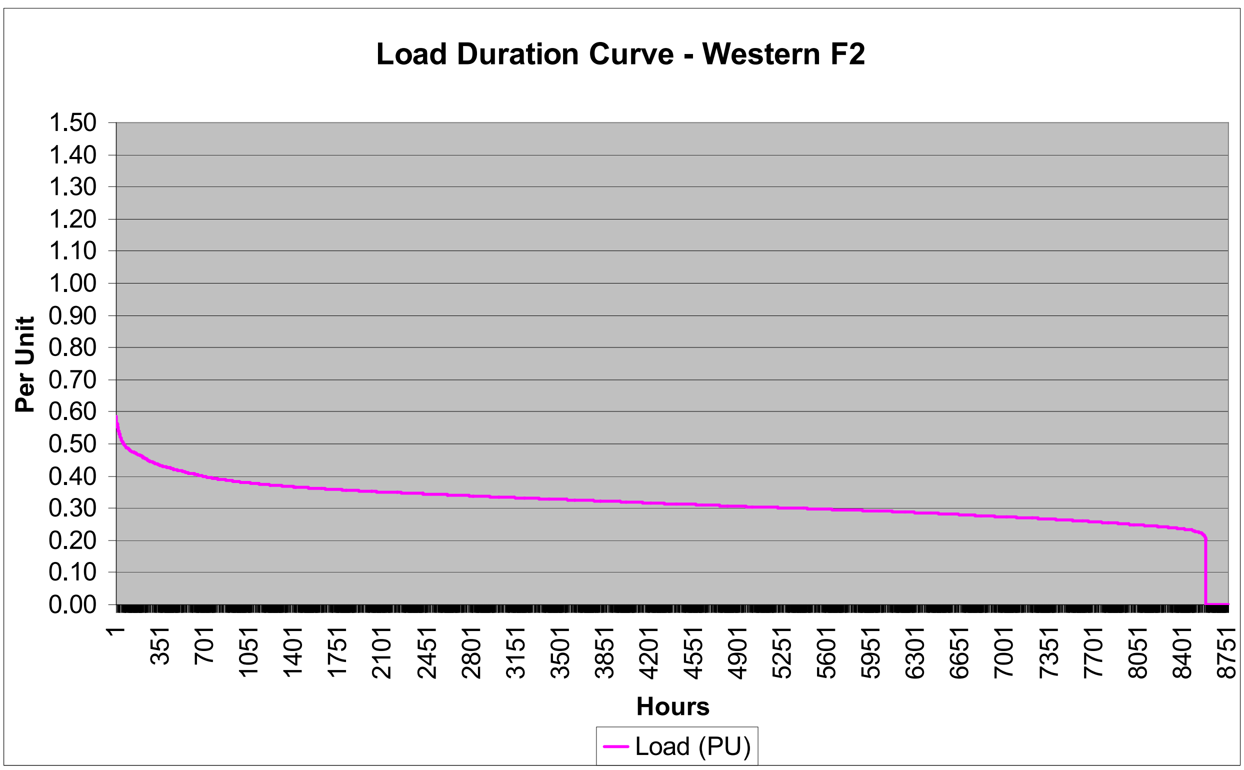
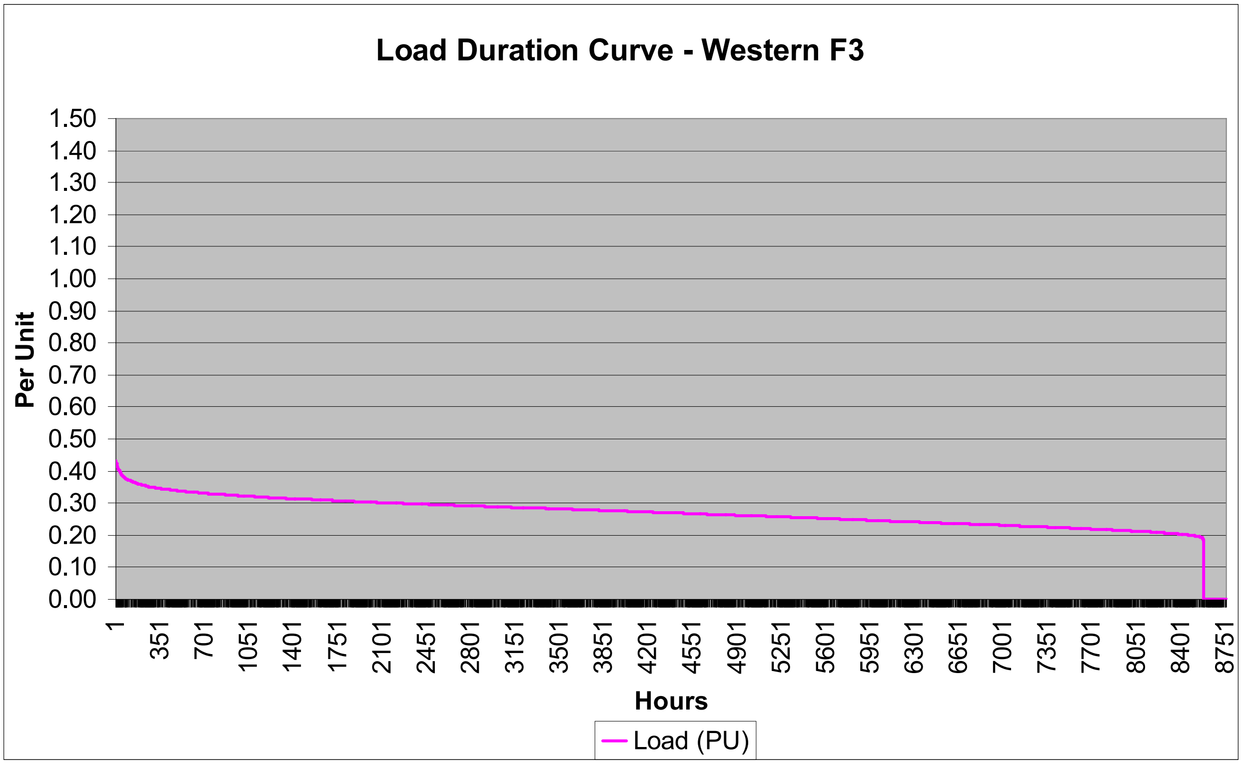
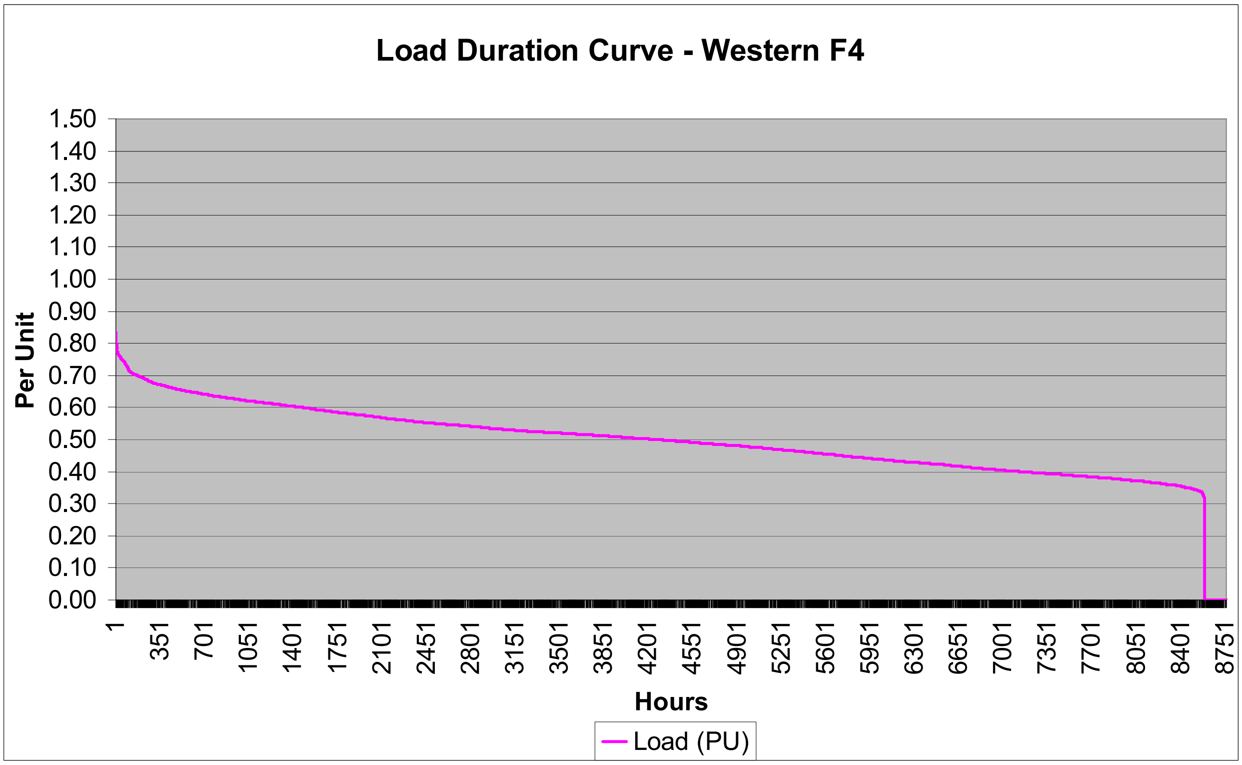
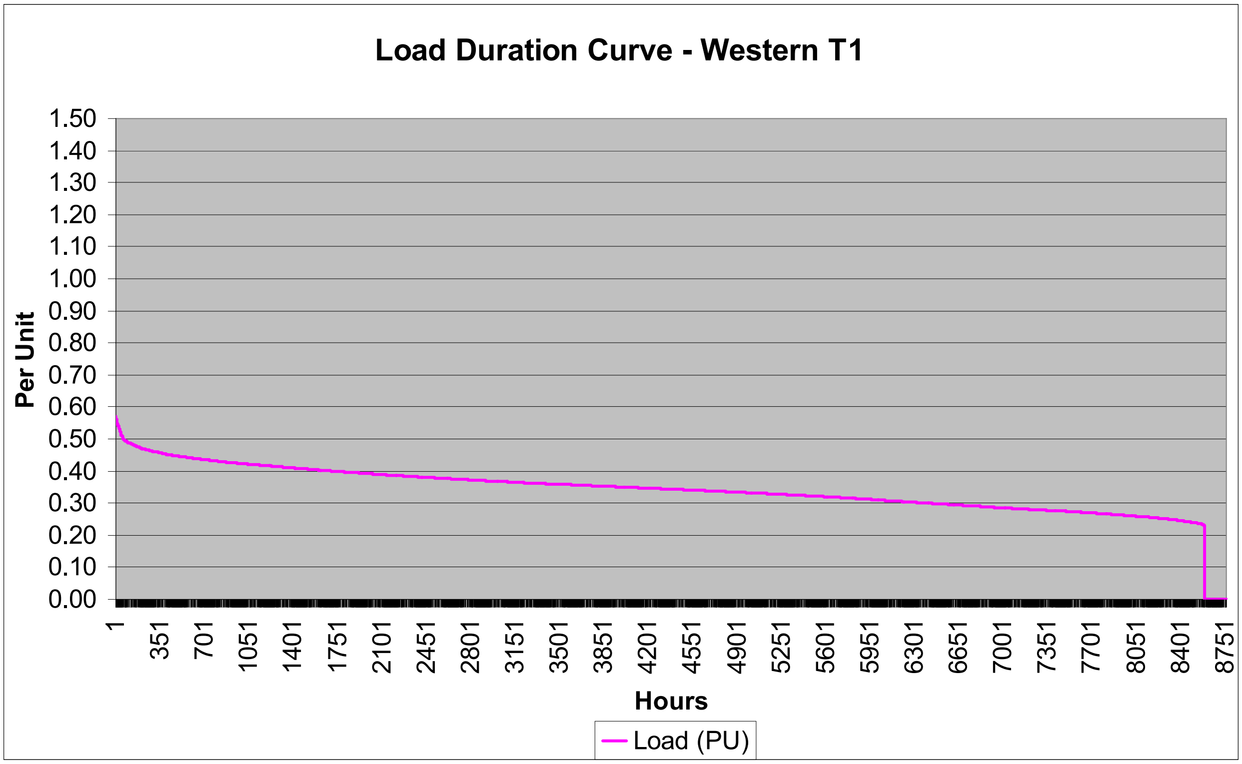
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Western F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

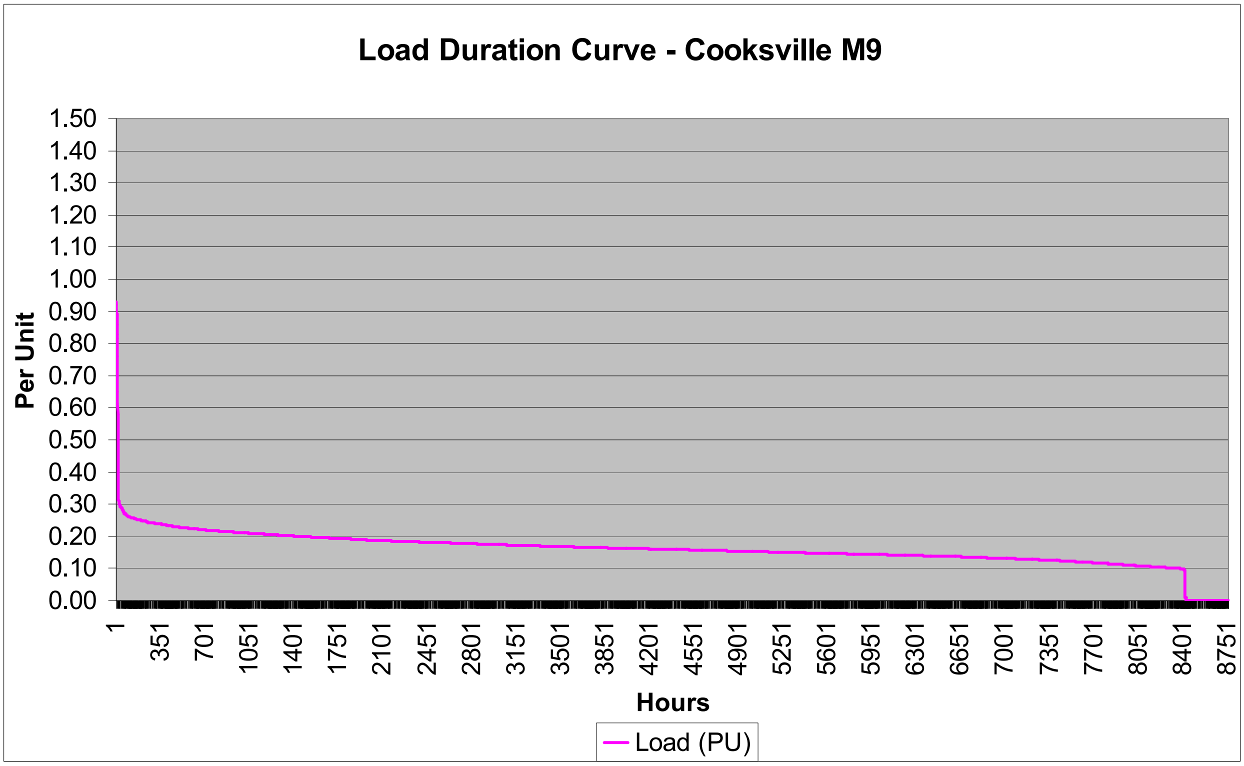

Load Duration Curve - Western F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

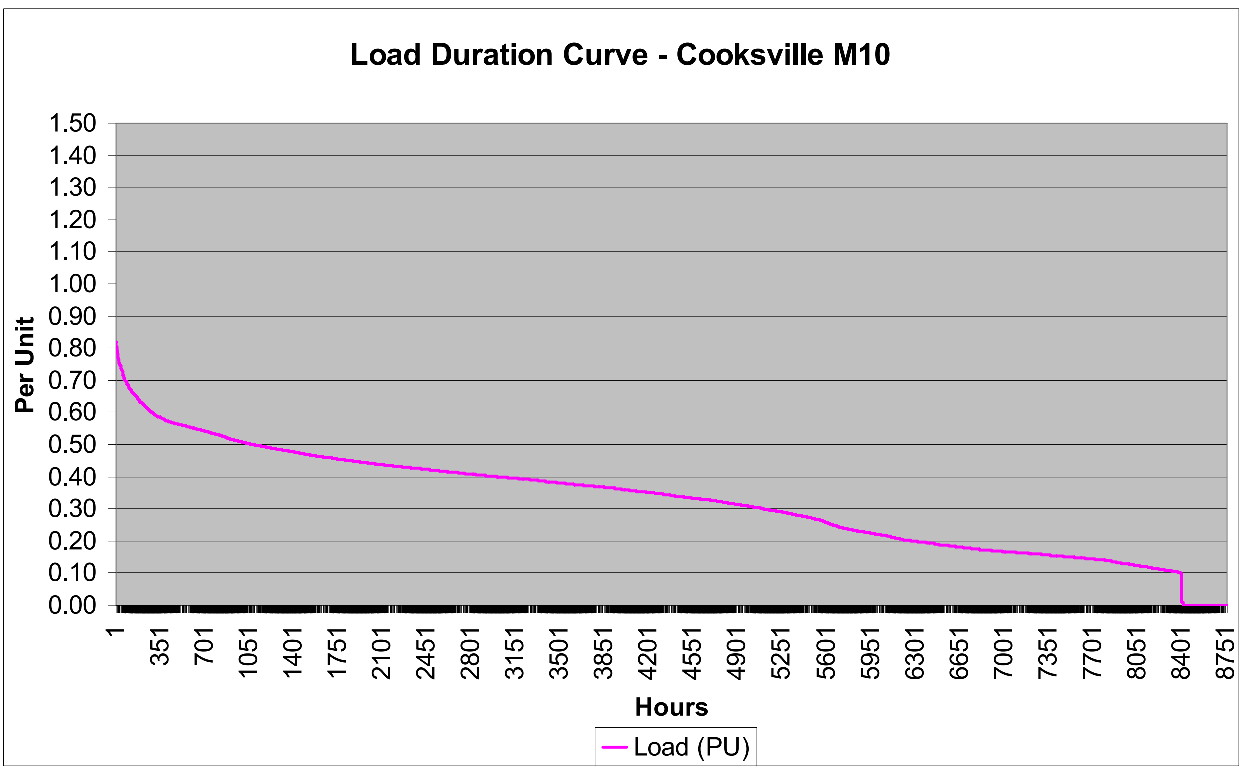

Load Duration Curve - Western F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

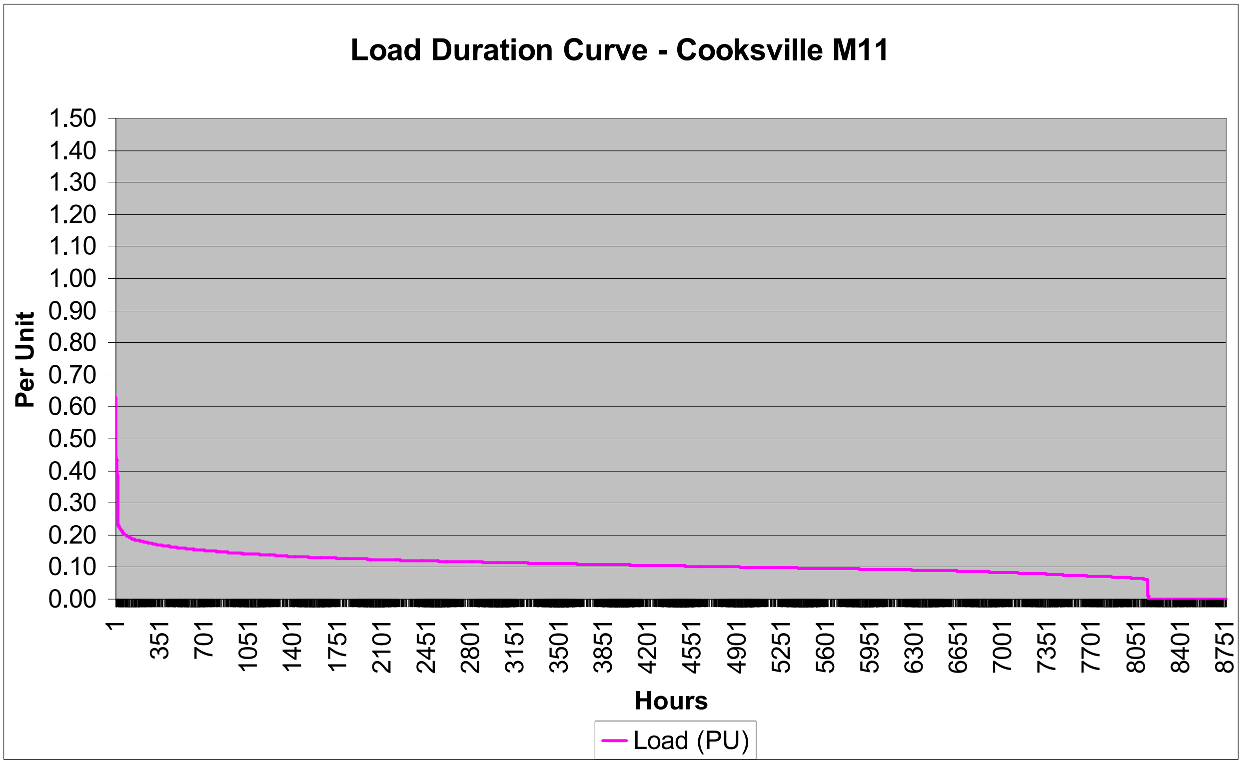

Load Duration Curve - Western T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

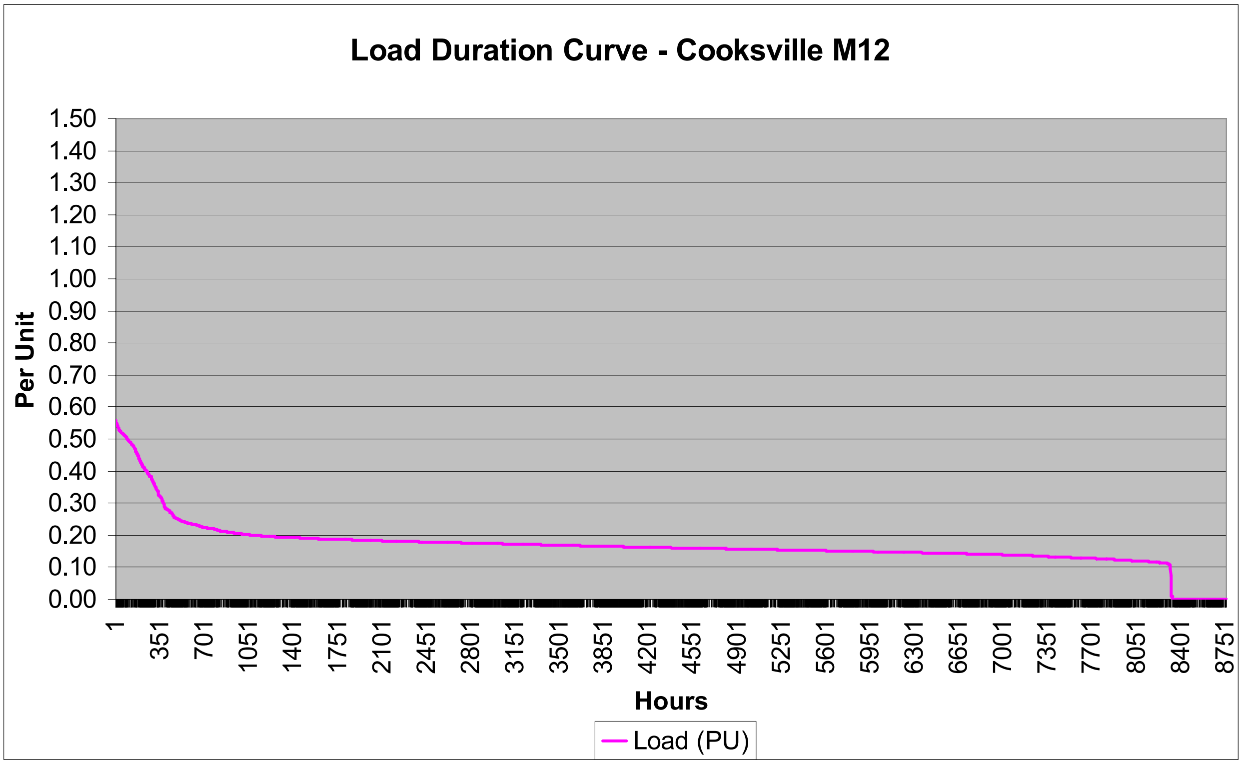
27.6 kV Transformer Stations

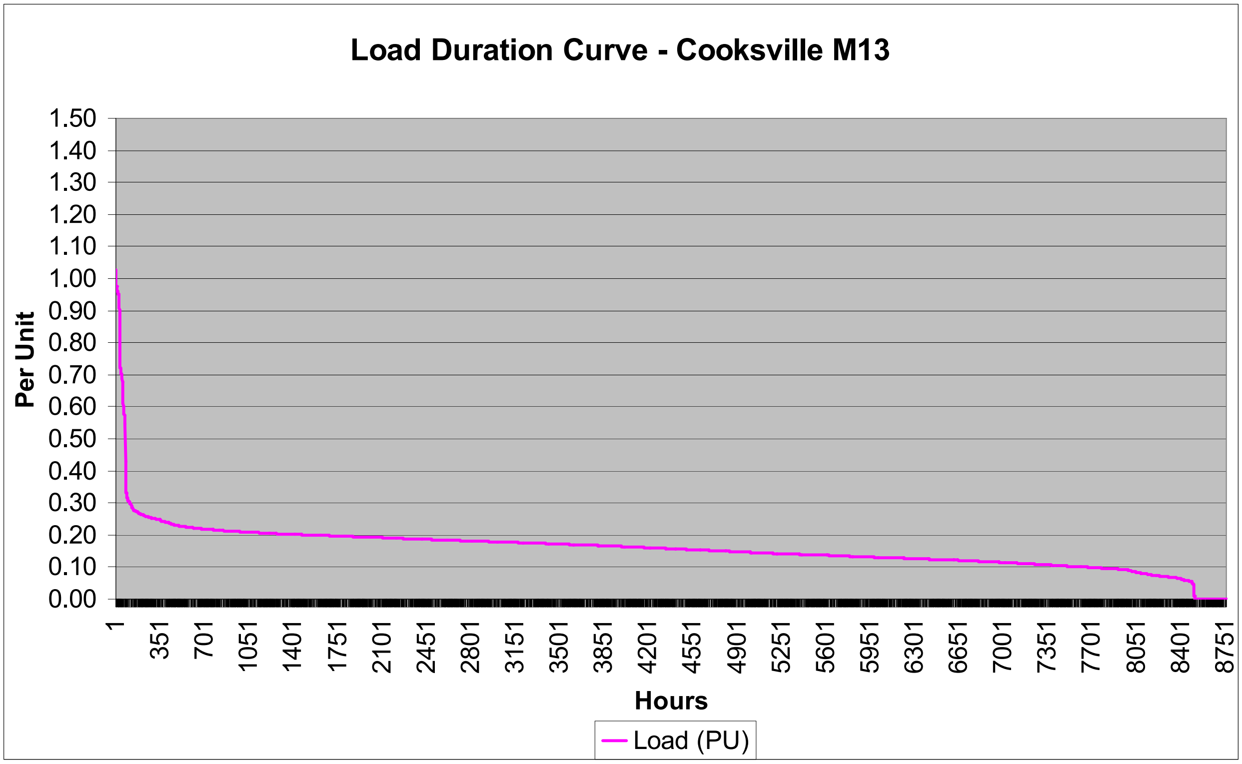
Cooksville TS

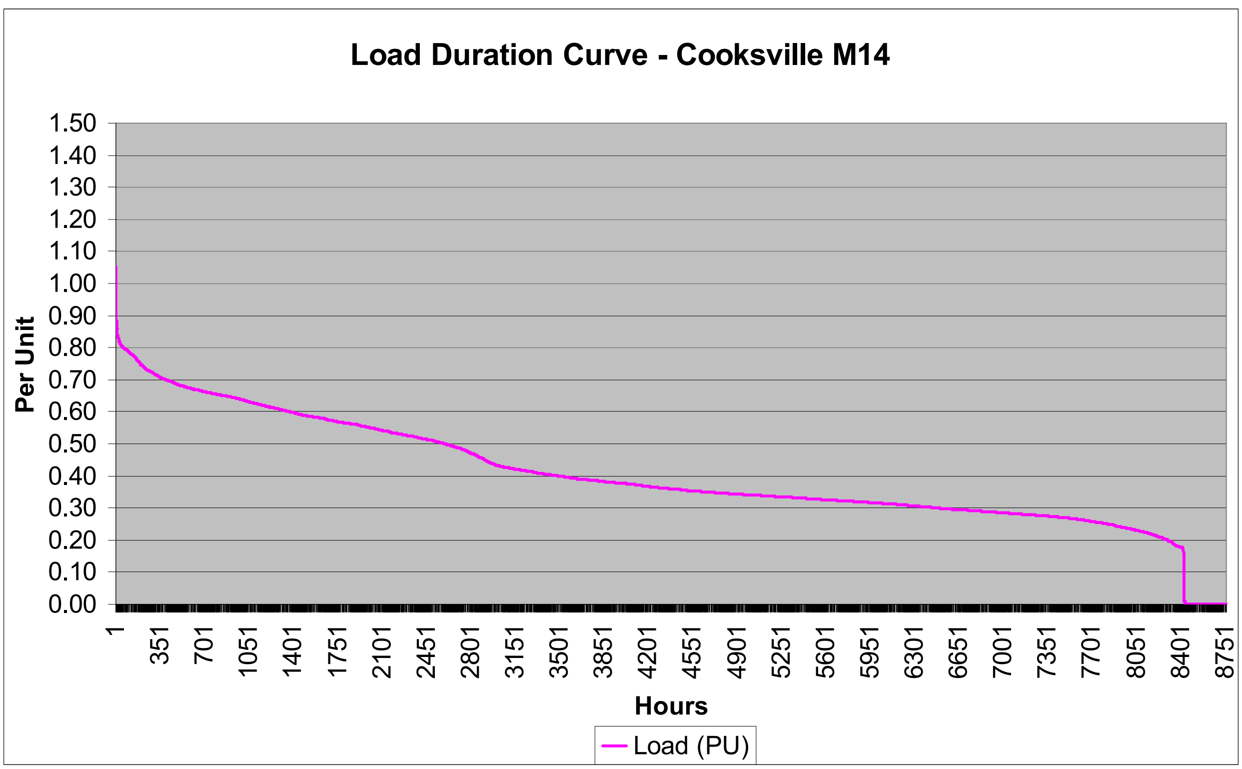


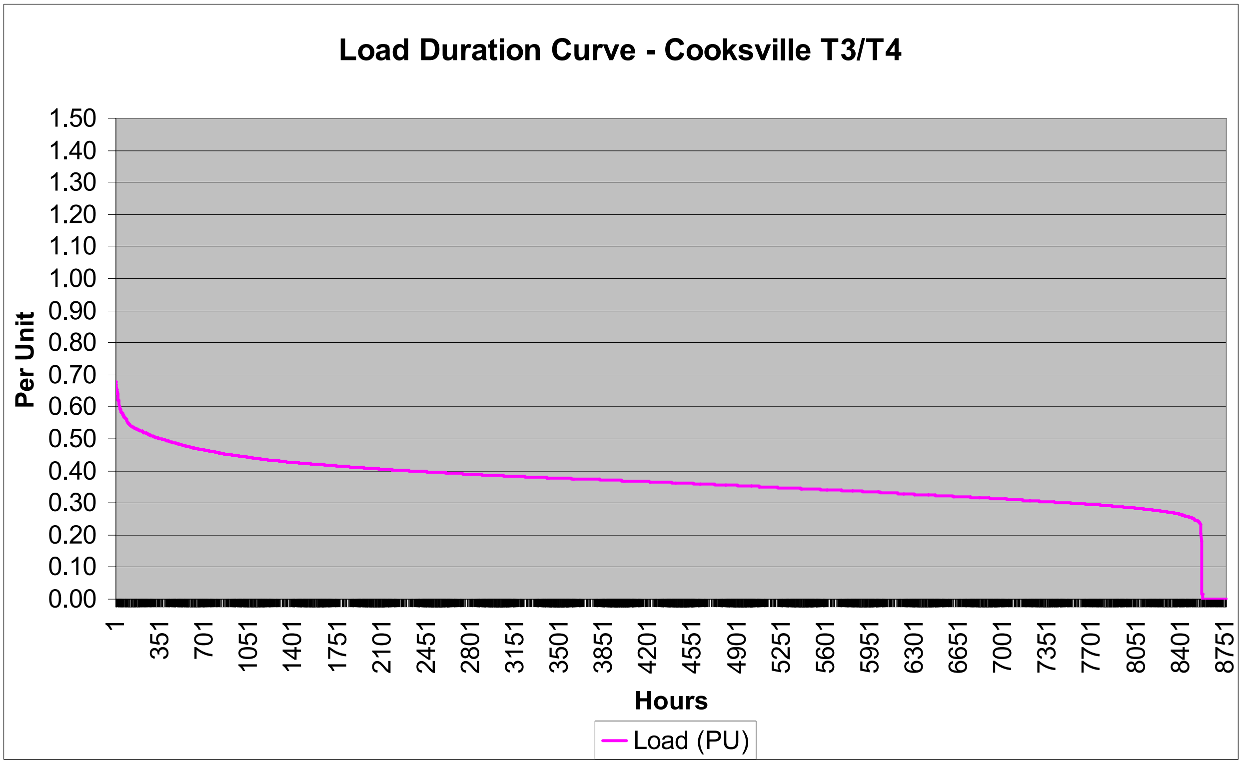



Load Duration Curve - Cooksville M11
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

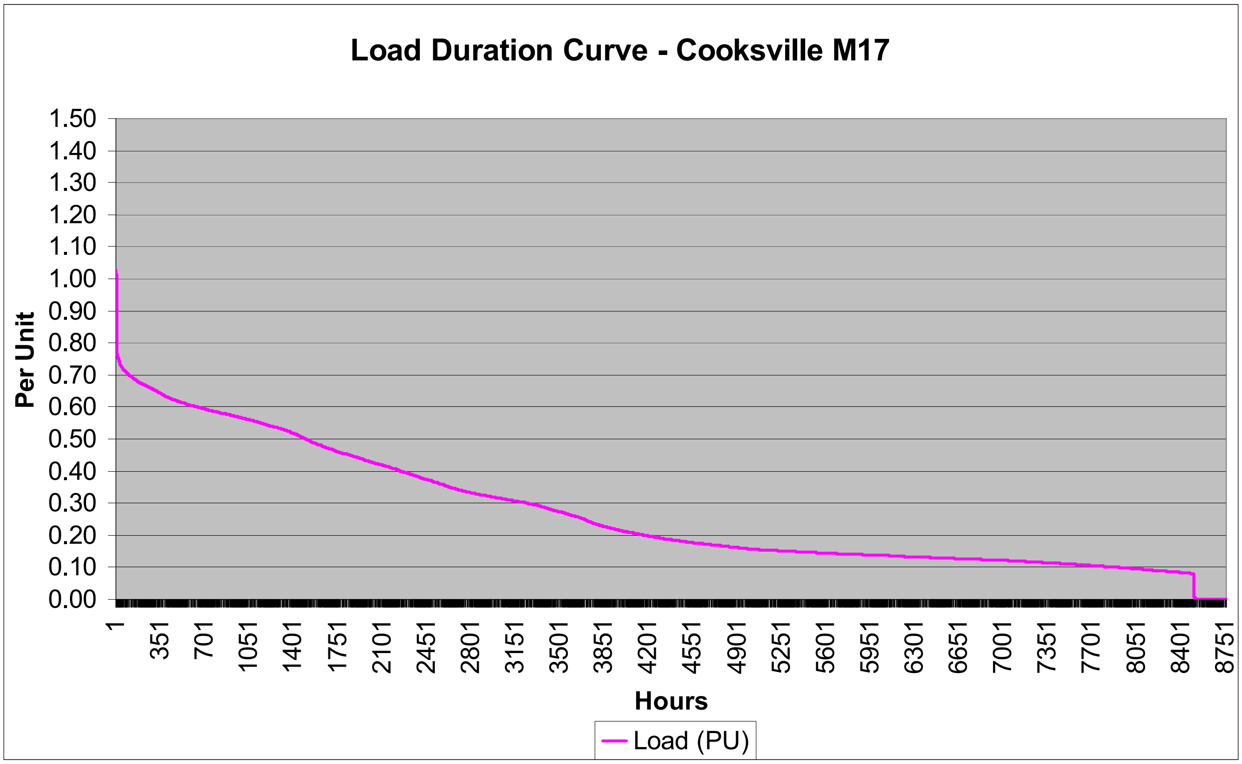

Load Duration Curve - Cooksville M12
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville M13
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

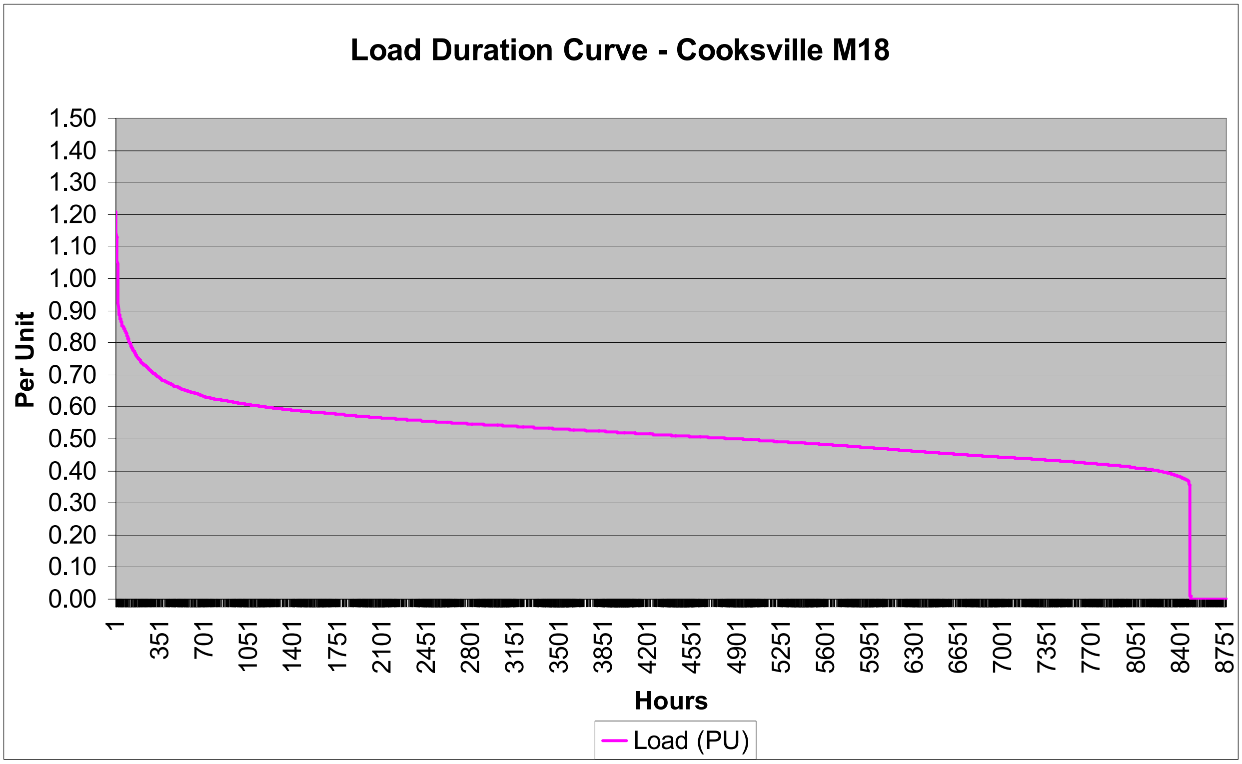

Load Duration Curve - Cooksville M14
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

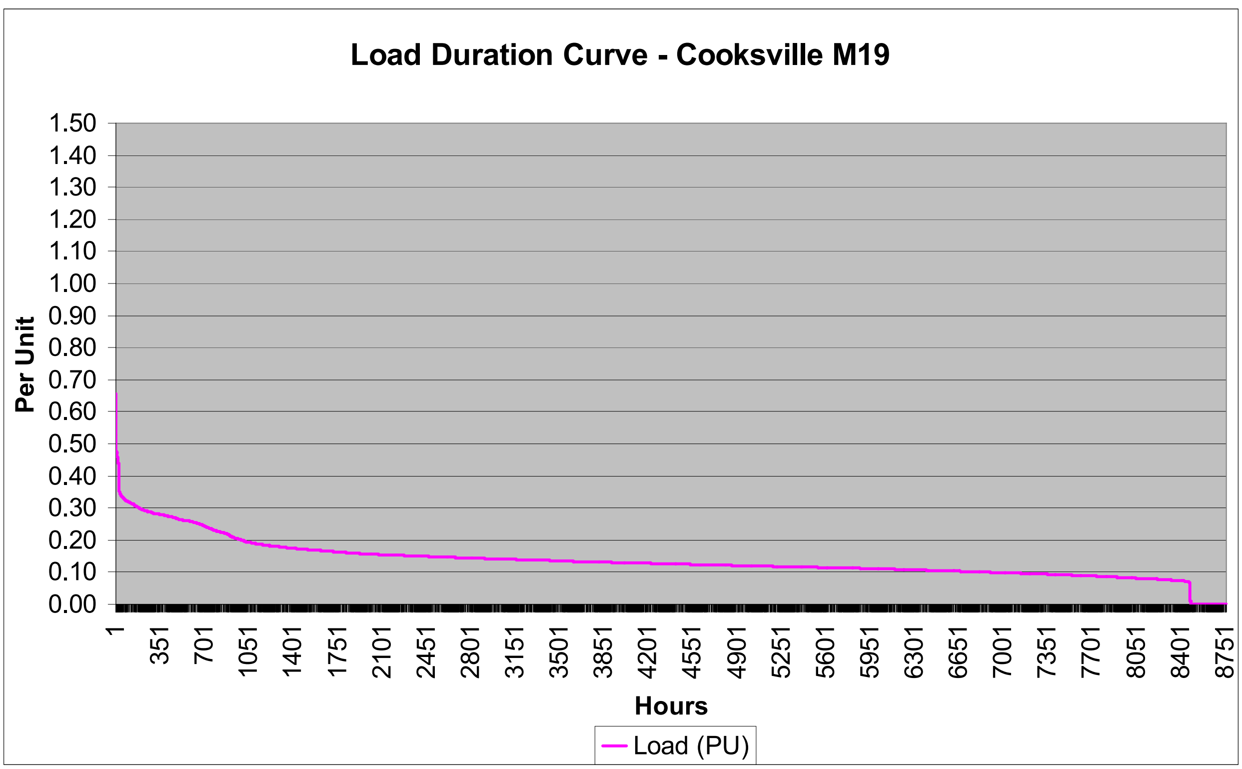


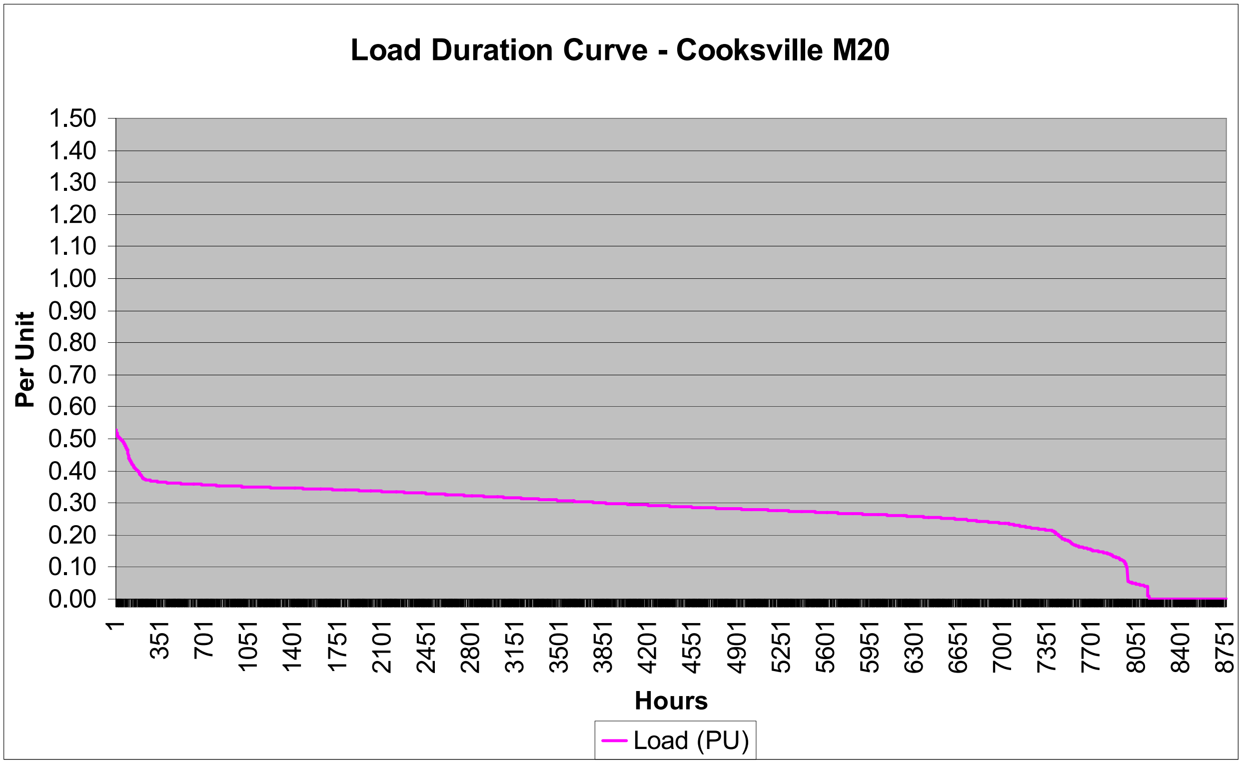
Load Duration Curve - Cooksville T3/T4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

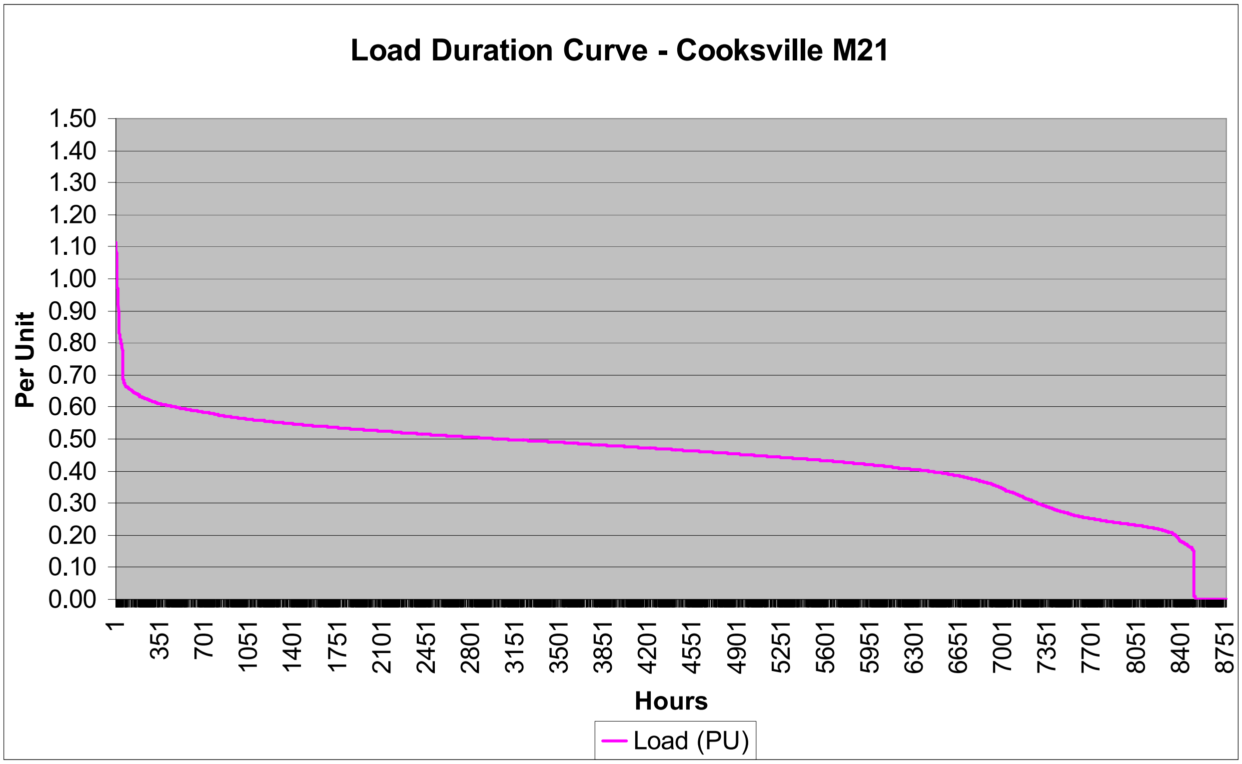


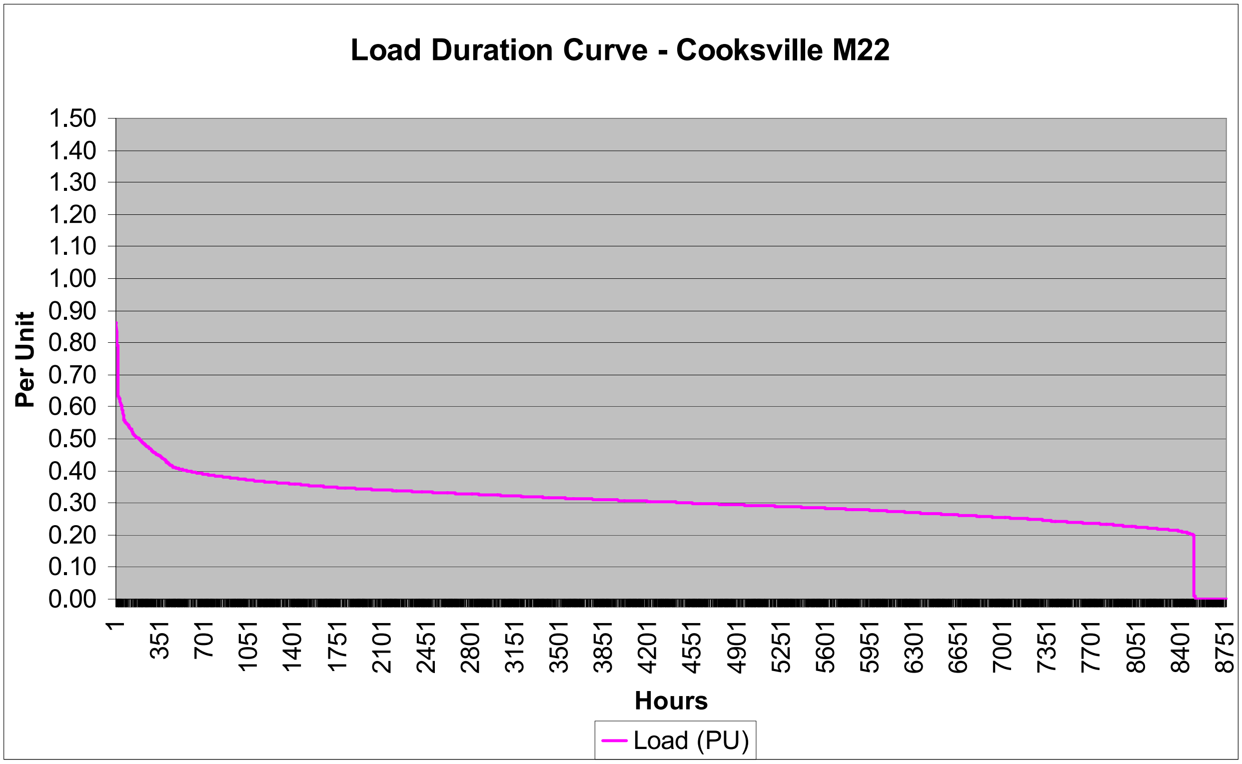
Load Duration Curve - Cooksville M17
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville M18
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville M19
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville M20
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville M21
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville M22
Per Unit
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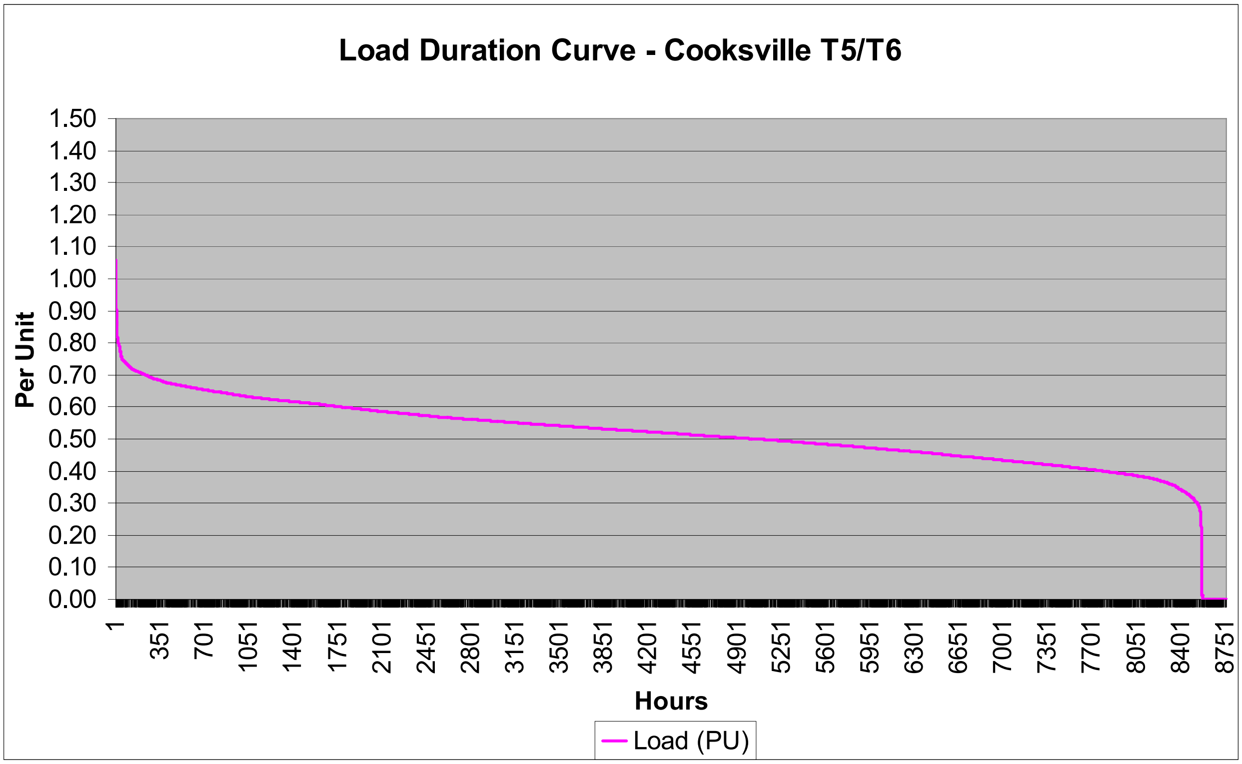
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cooksville T5/T6
Per Unit
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1.40
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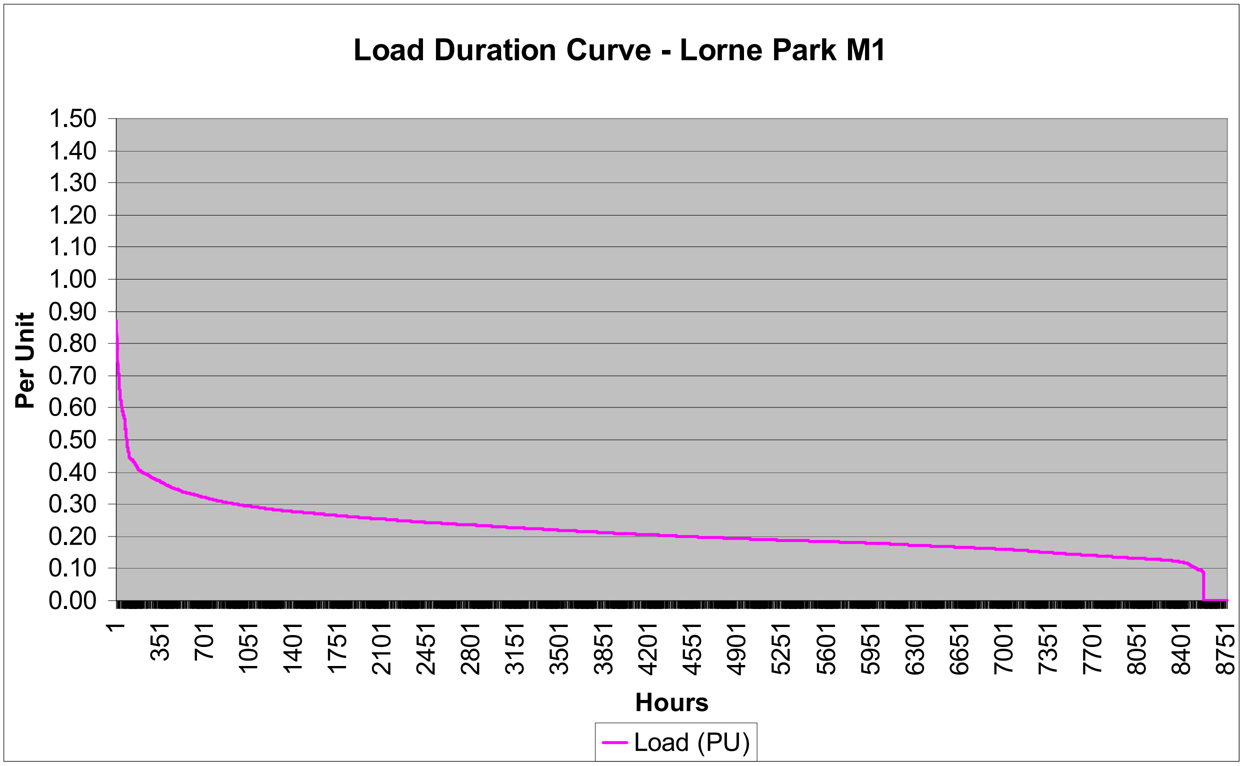
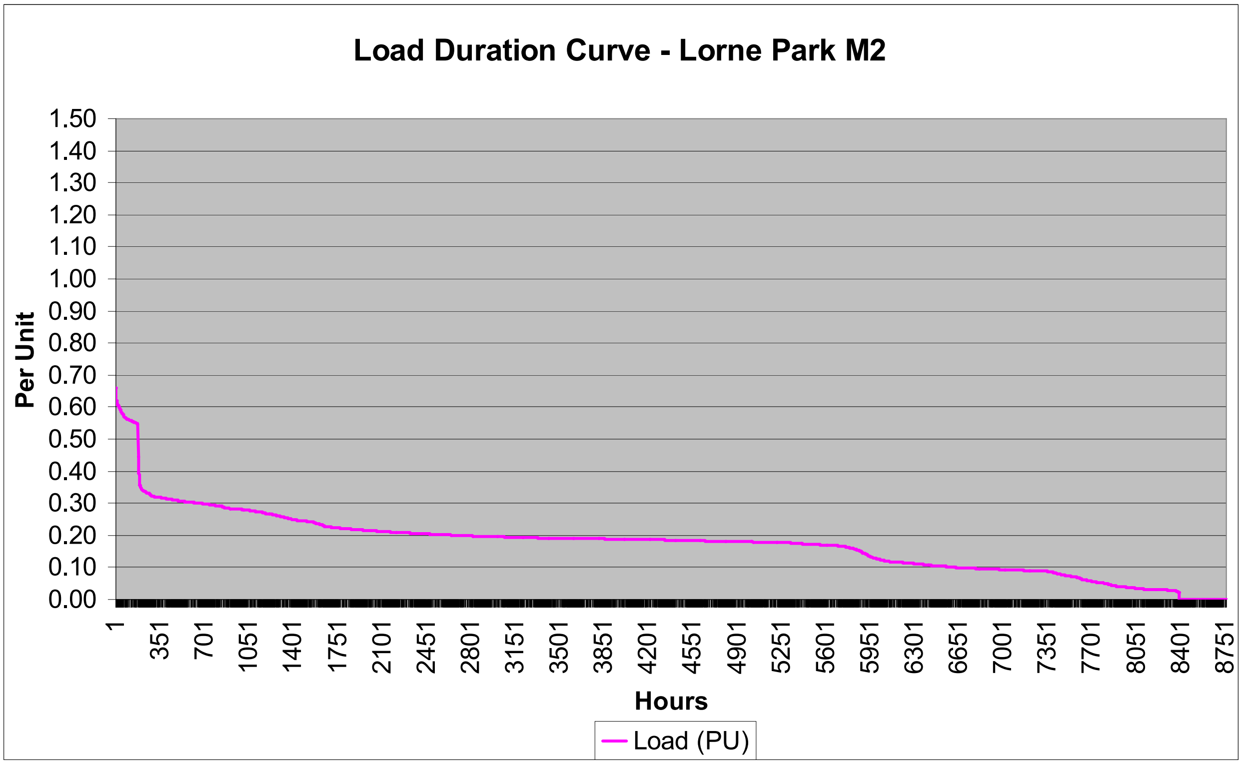
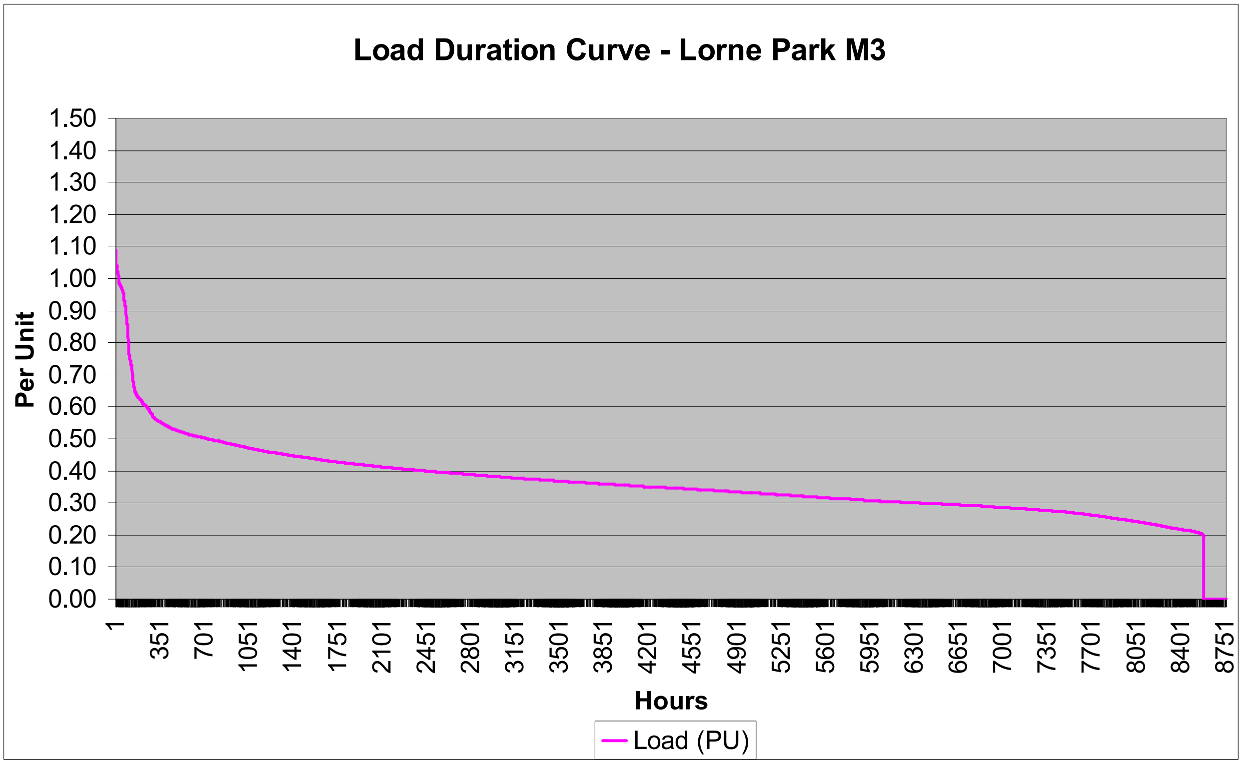
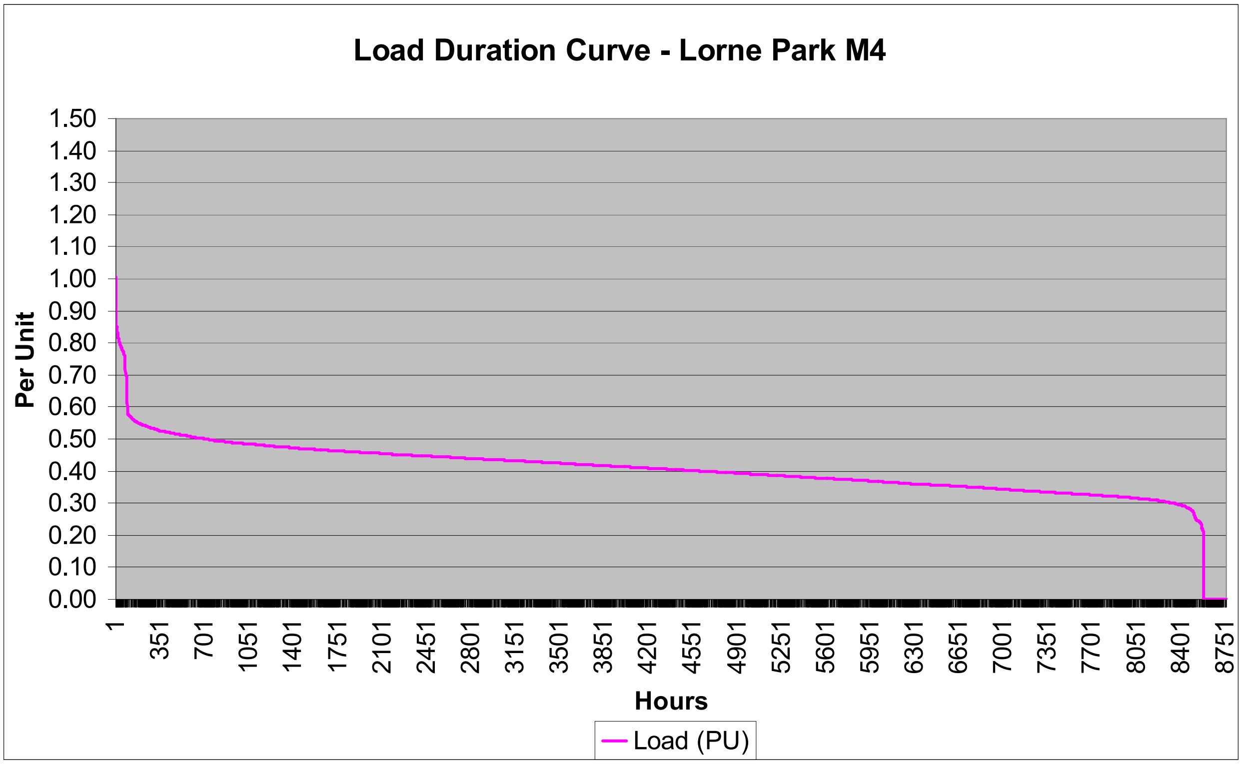
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

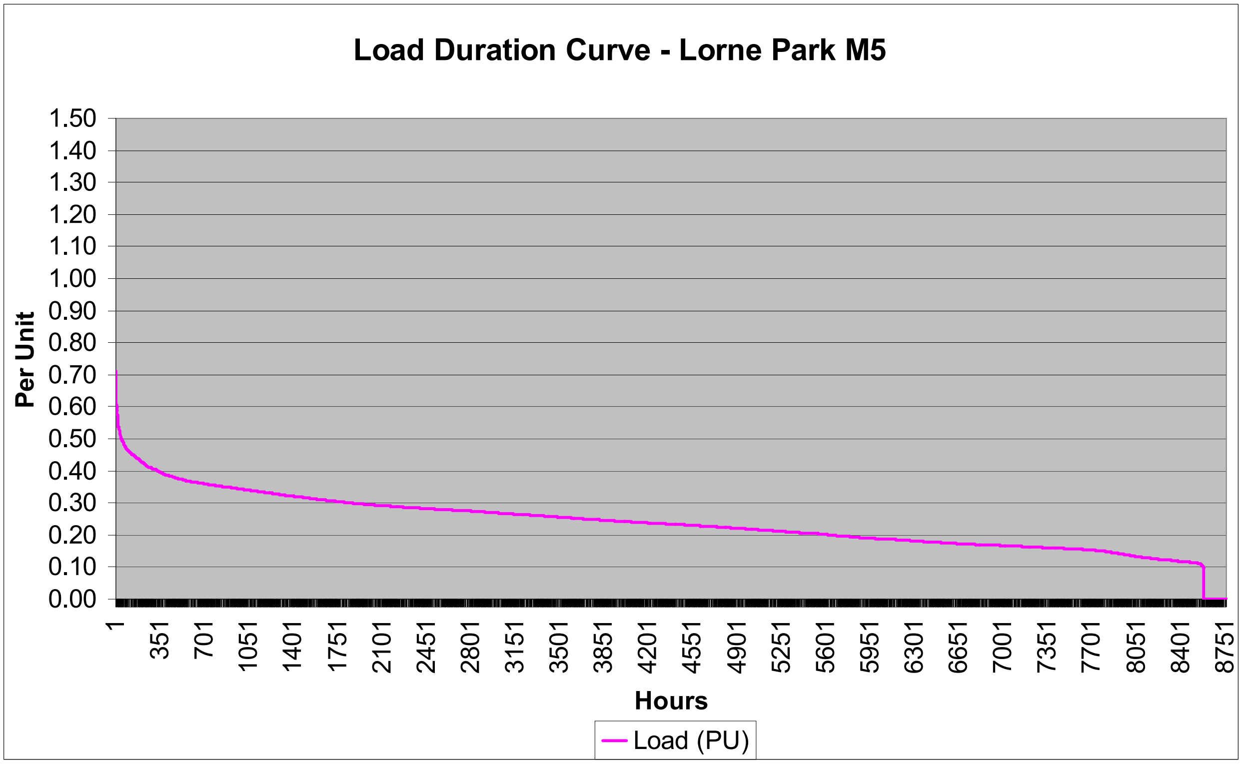
Lorne Park TS

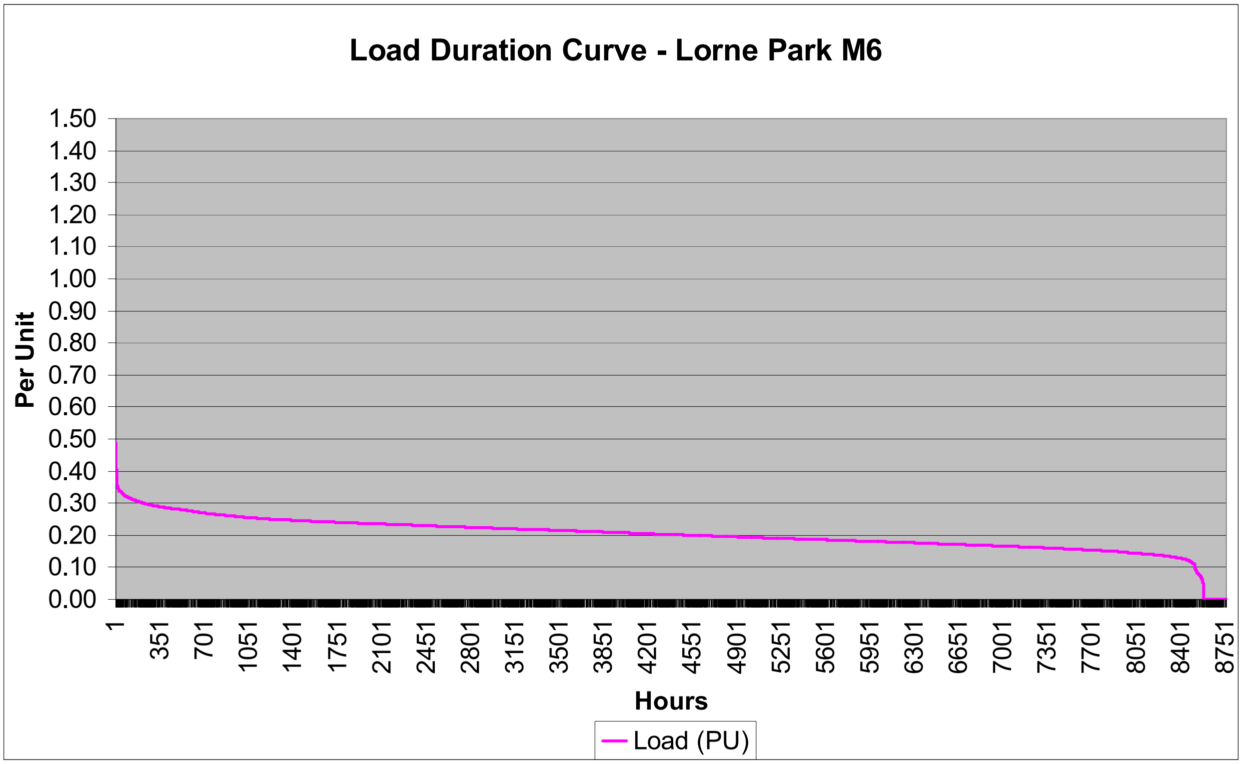


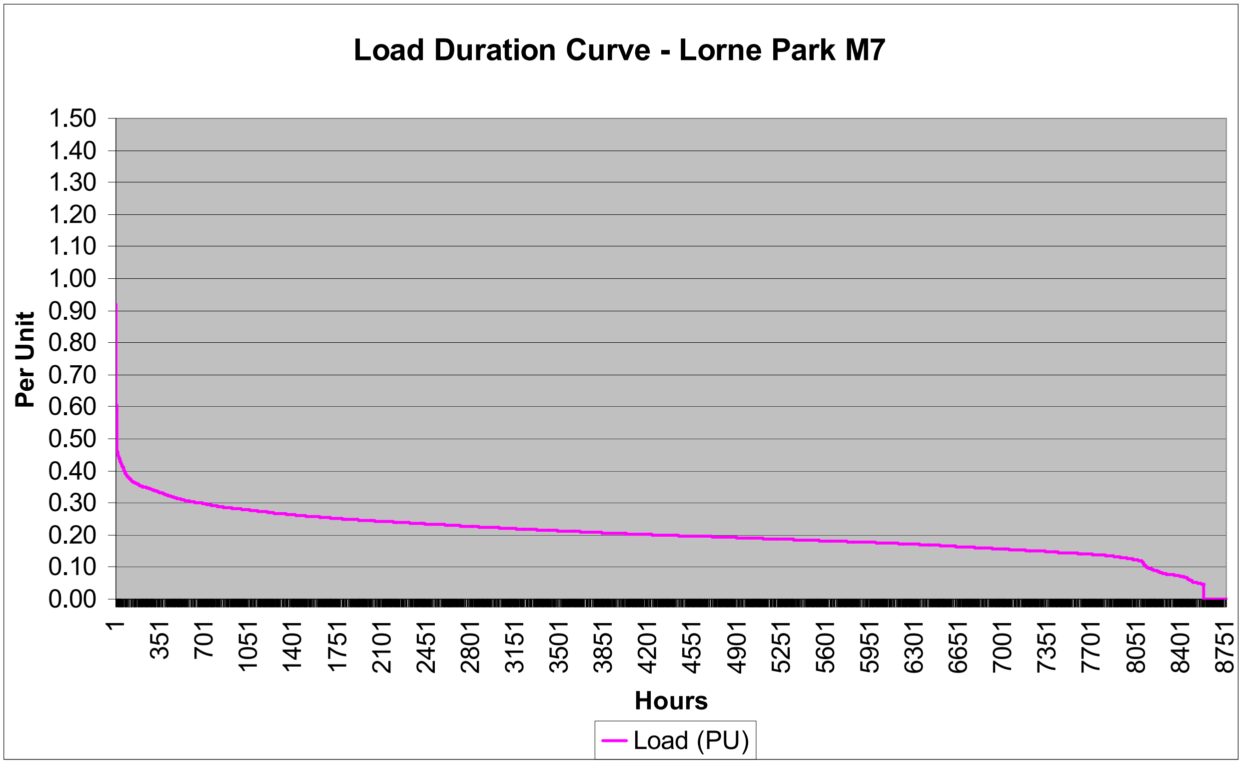



Load Duration Curve - Lorne Park M3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M7
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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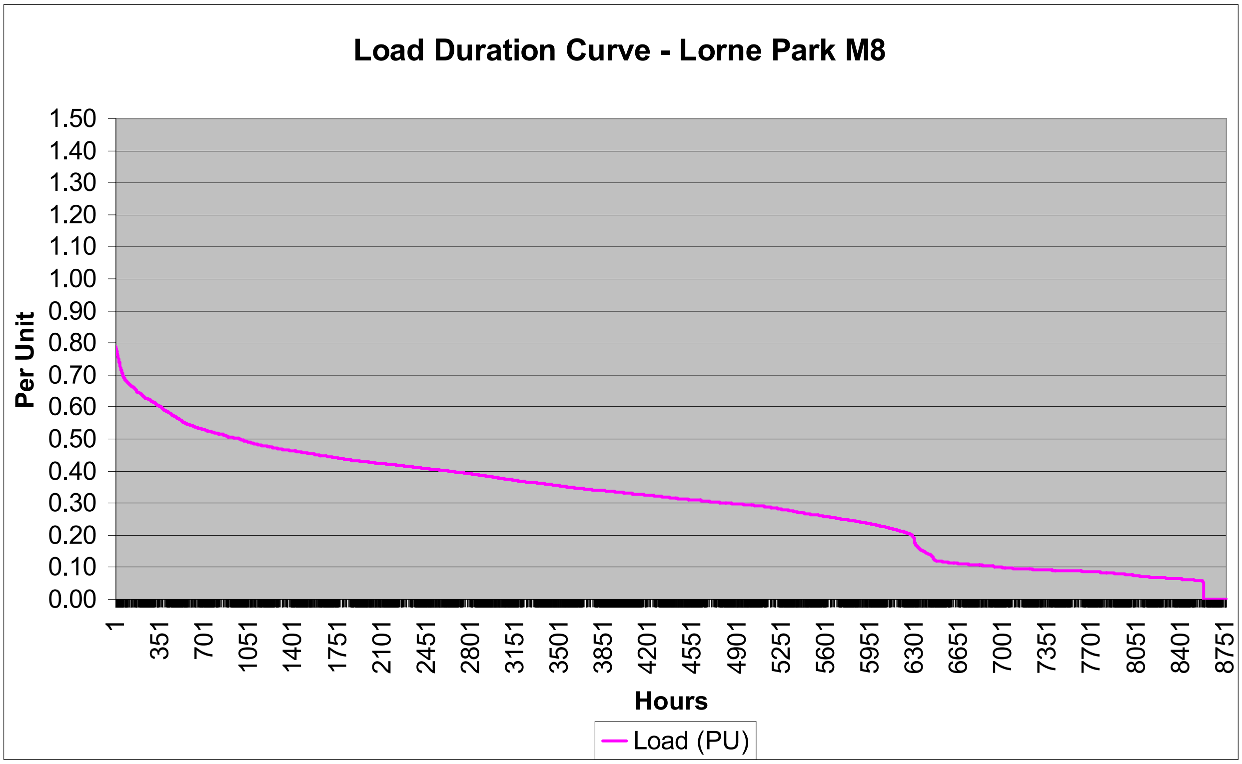
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M8
Per Unit
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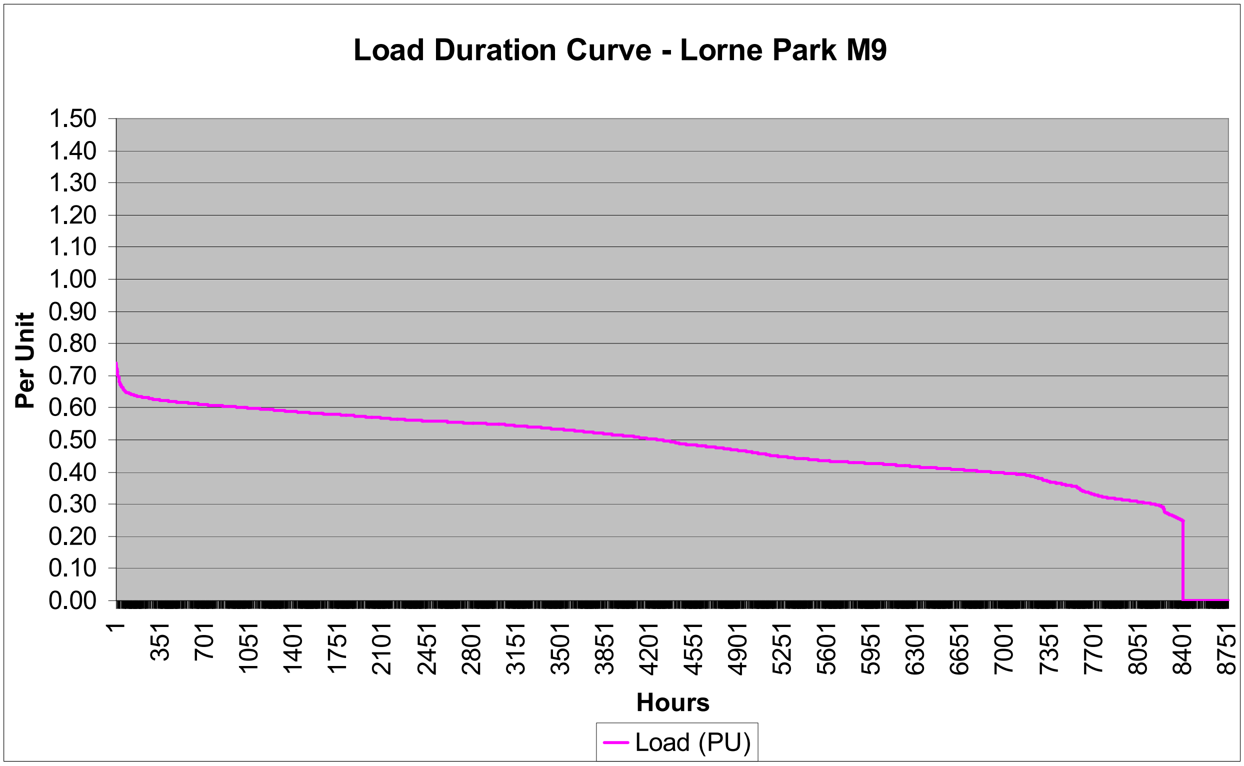
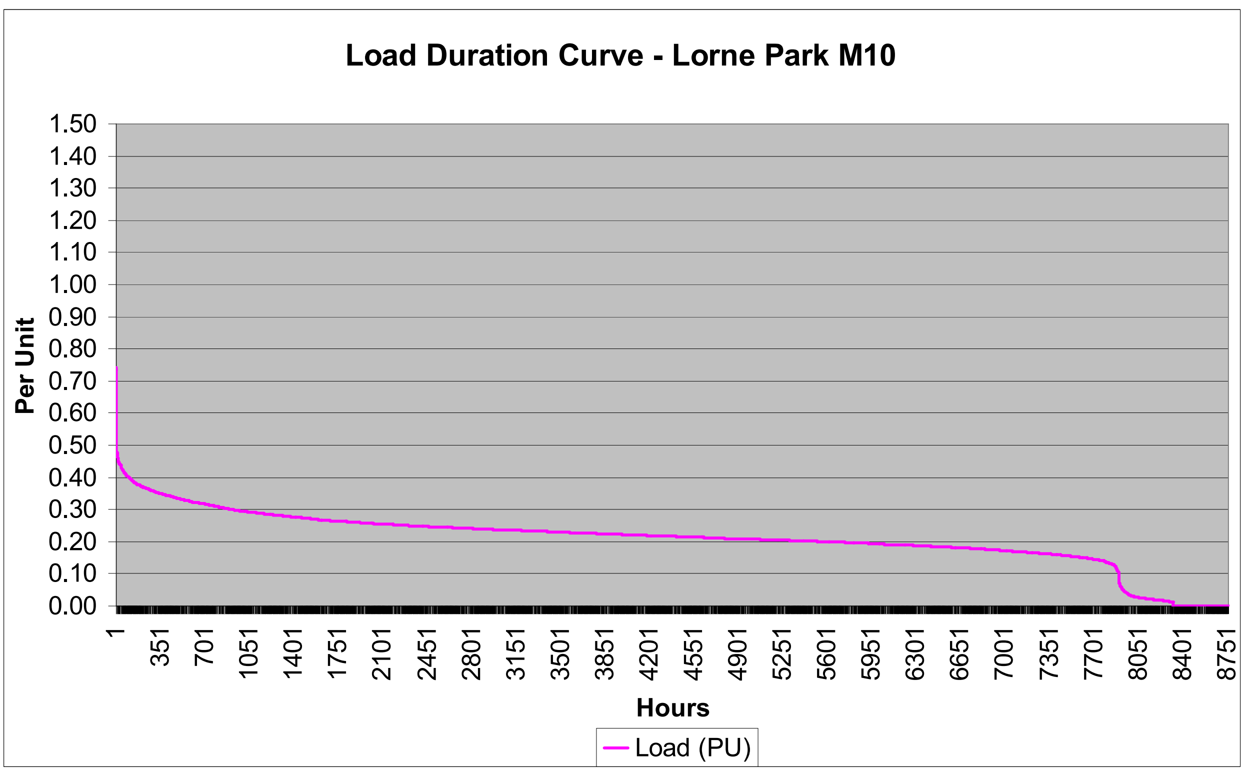
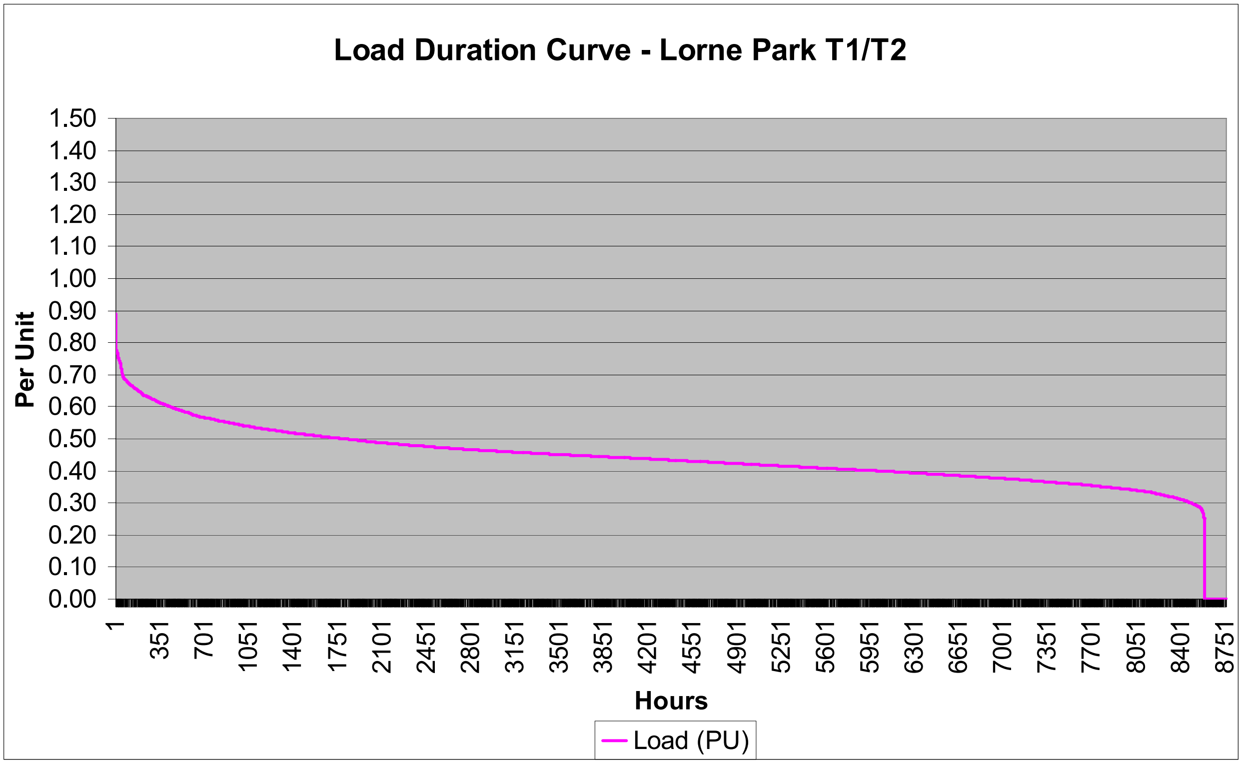
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M9
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lorne Park M10
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Lorne Park T1/T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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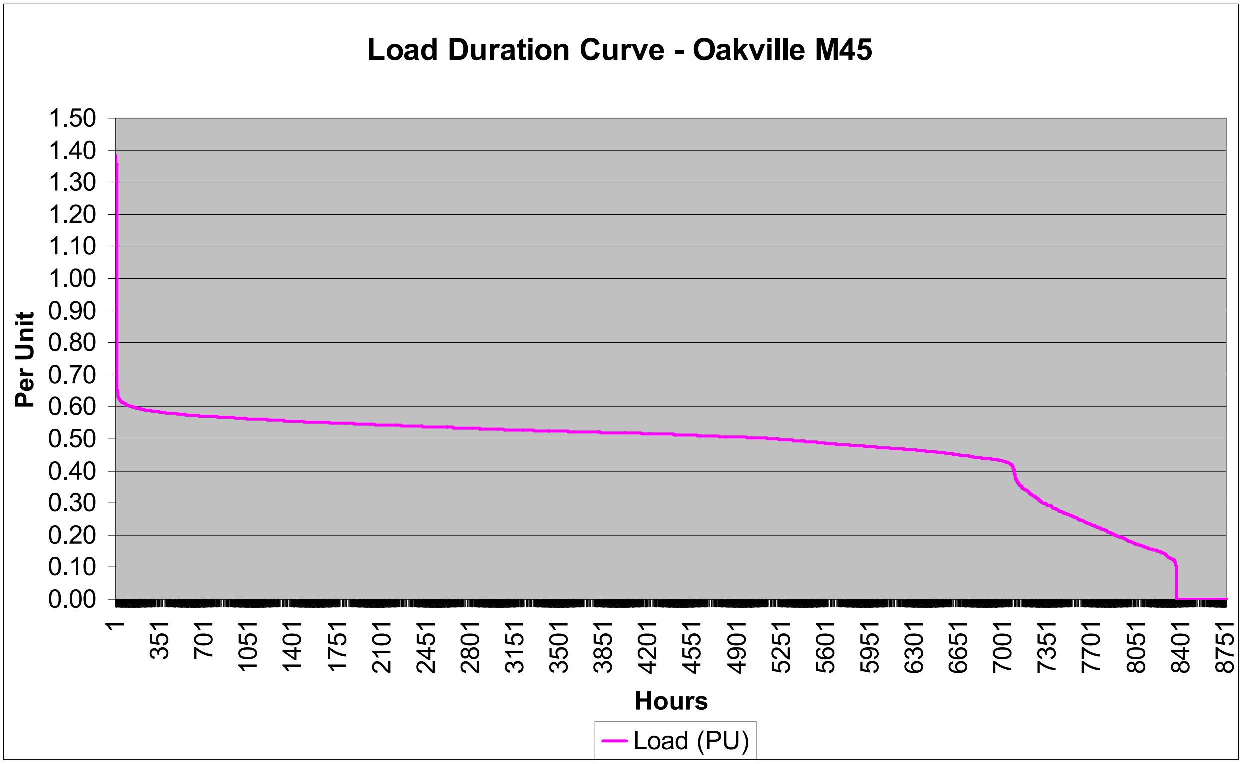
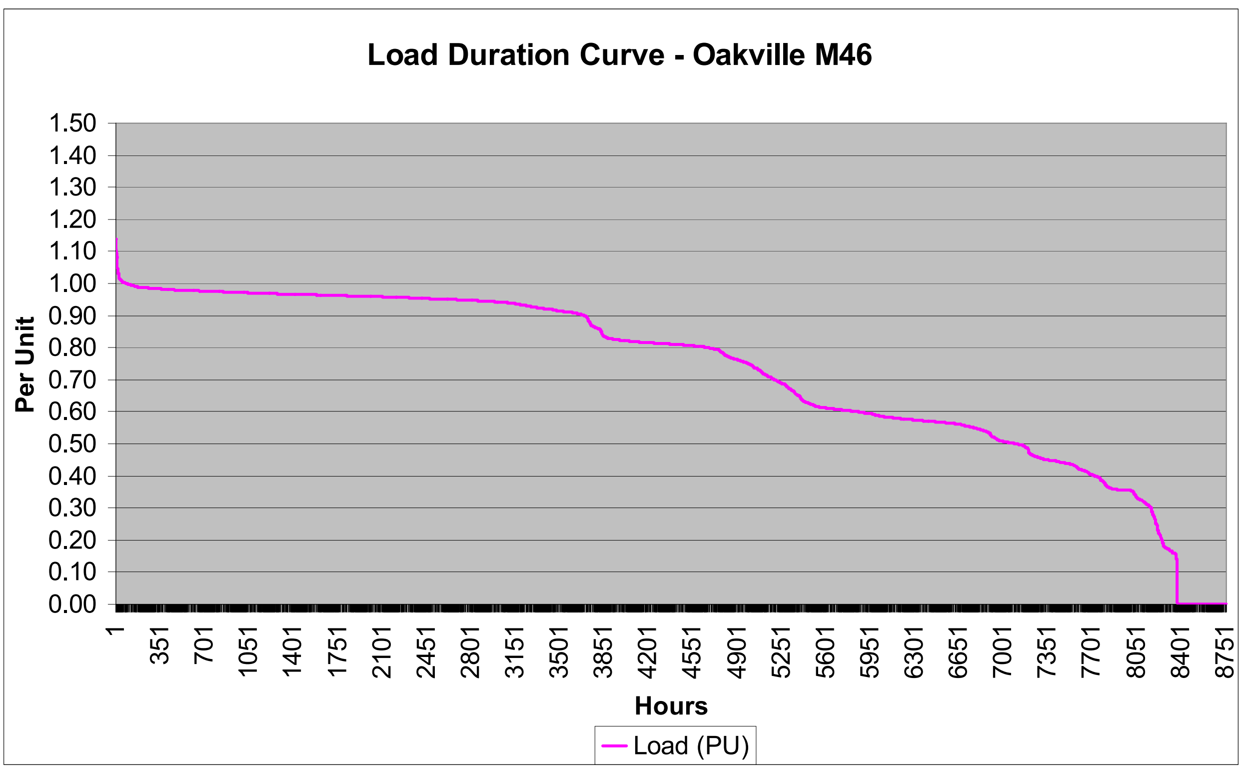
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

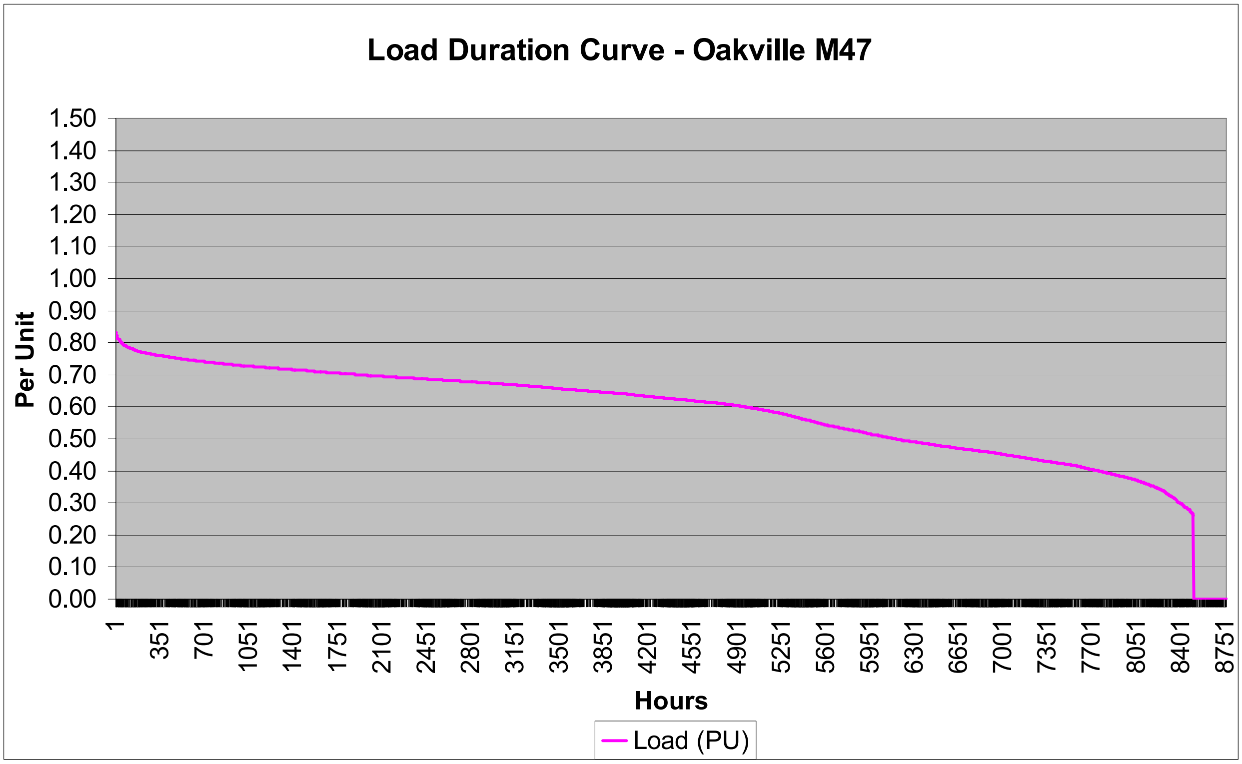
Oakville TS

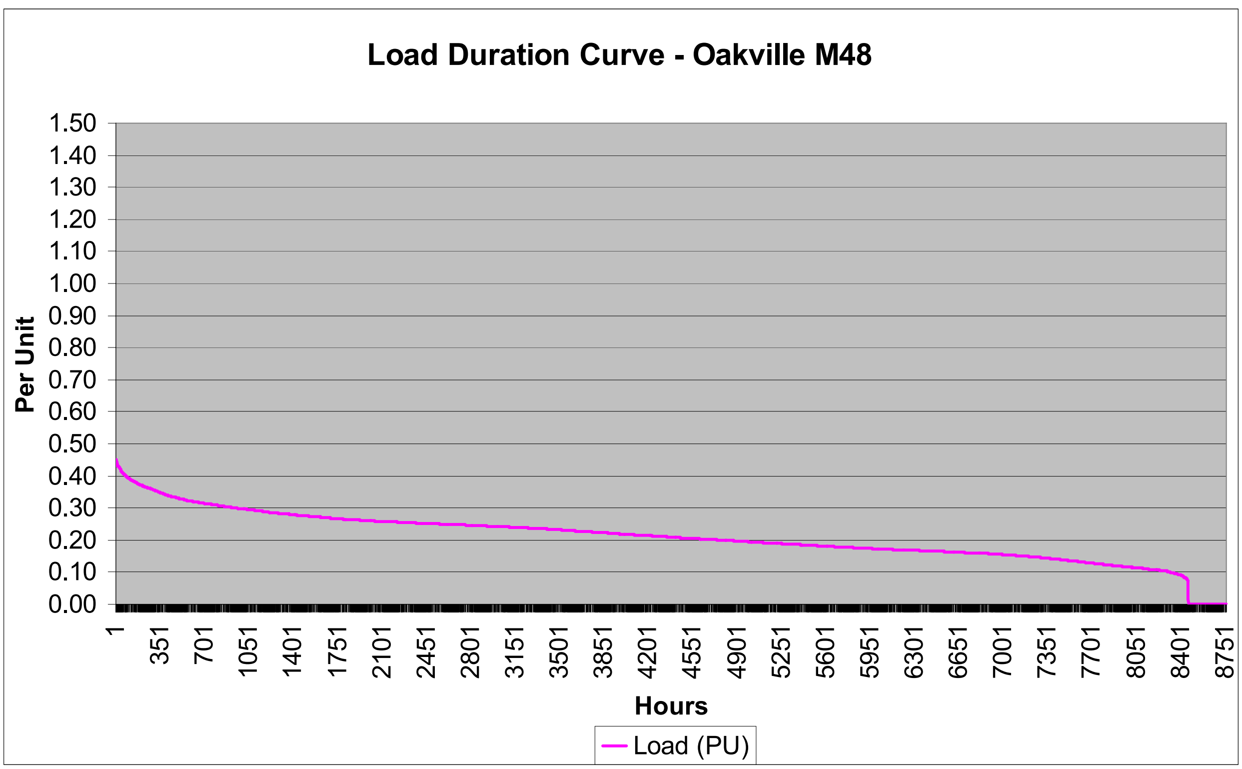


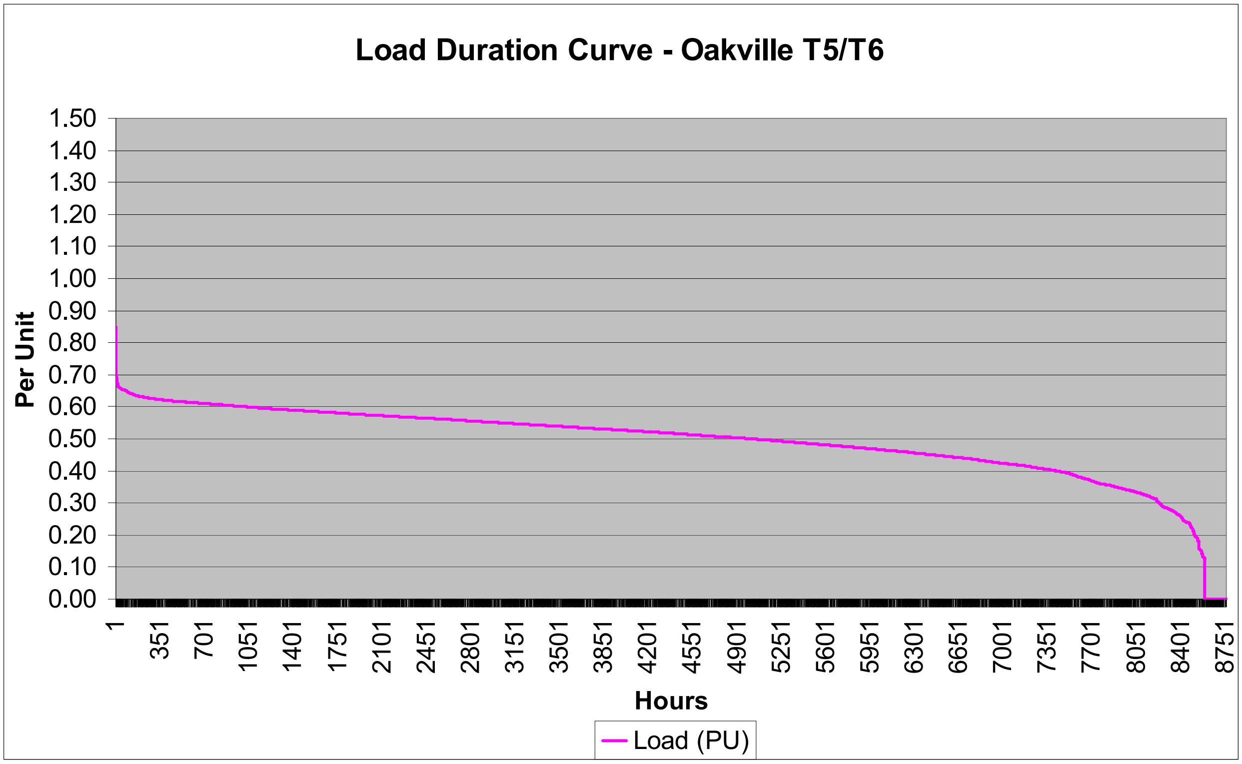
Load Duration Curve - Oakville M45
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Oakville M46
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Oakville M47
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

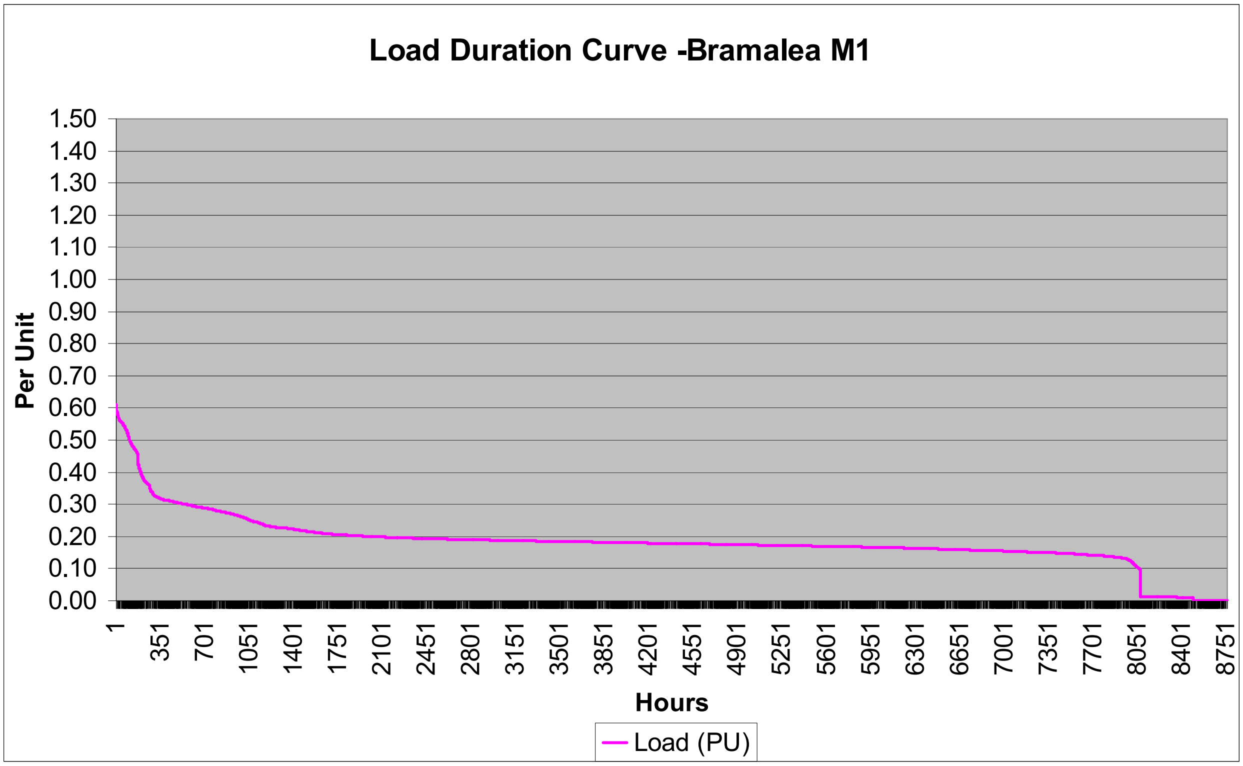

Load Duration Curve - Oakville M48
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

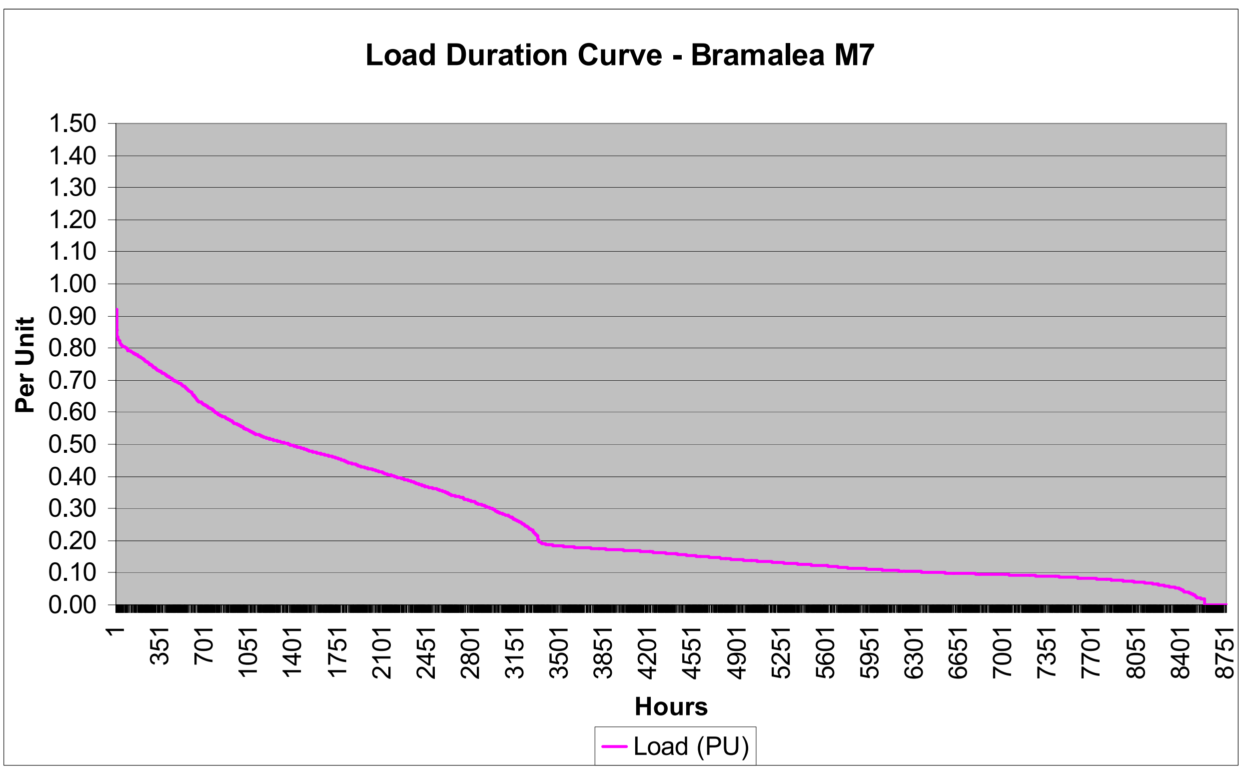


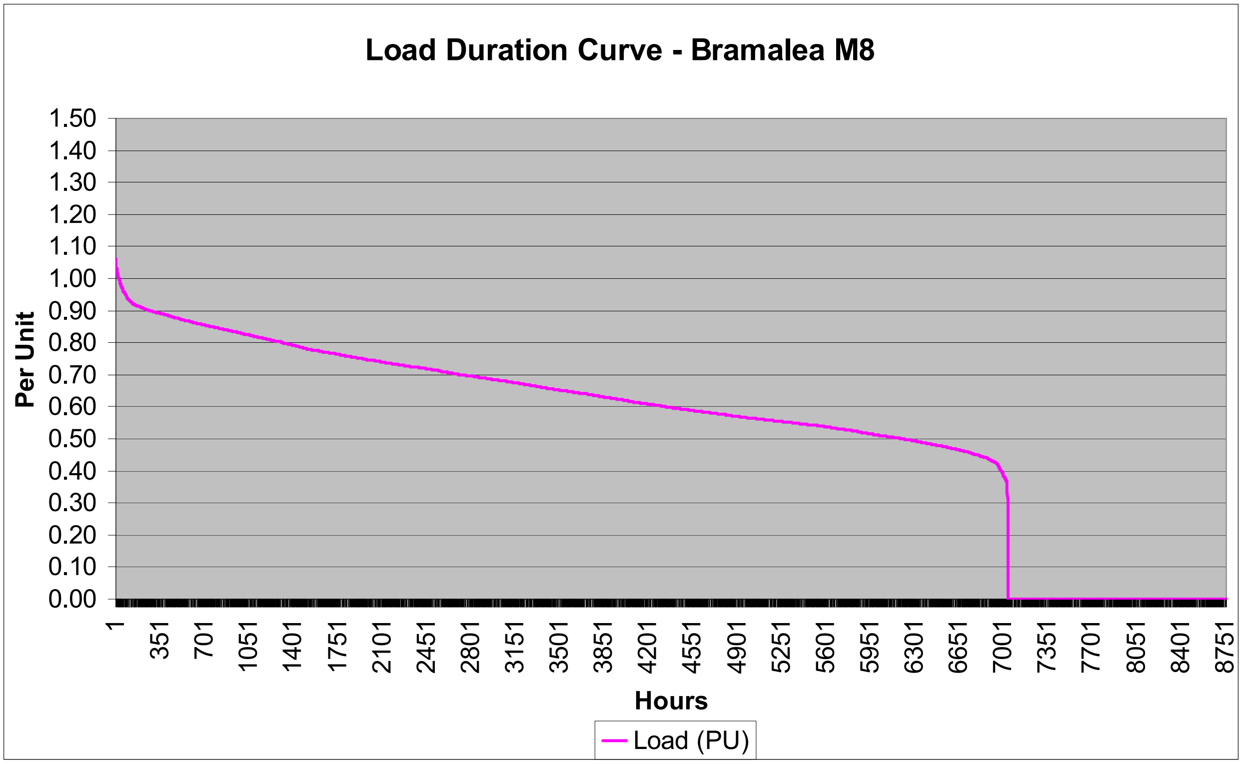
Load Duration Curve - Oakville T5/T6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

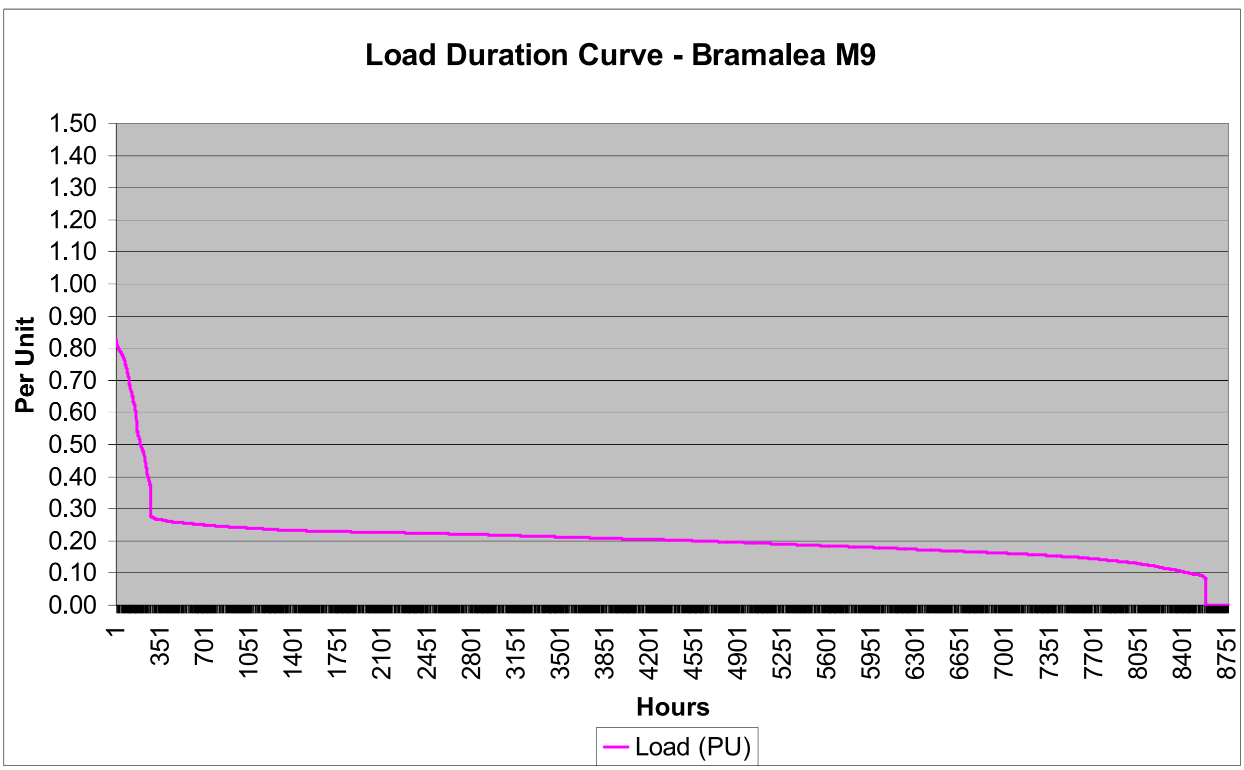
27.6 kV North System
27.6 kV Transformer Stations

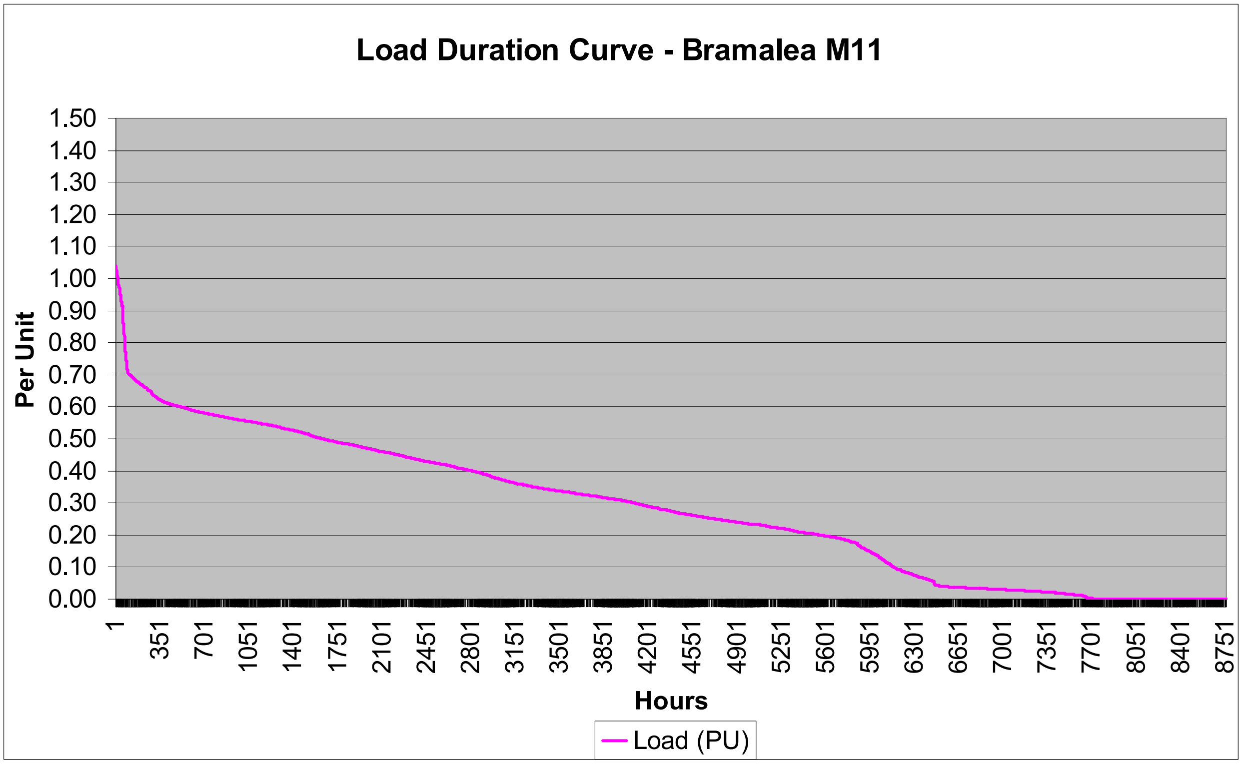
Bramalea TS

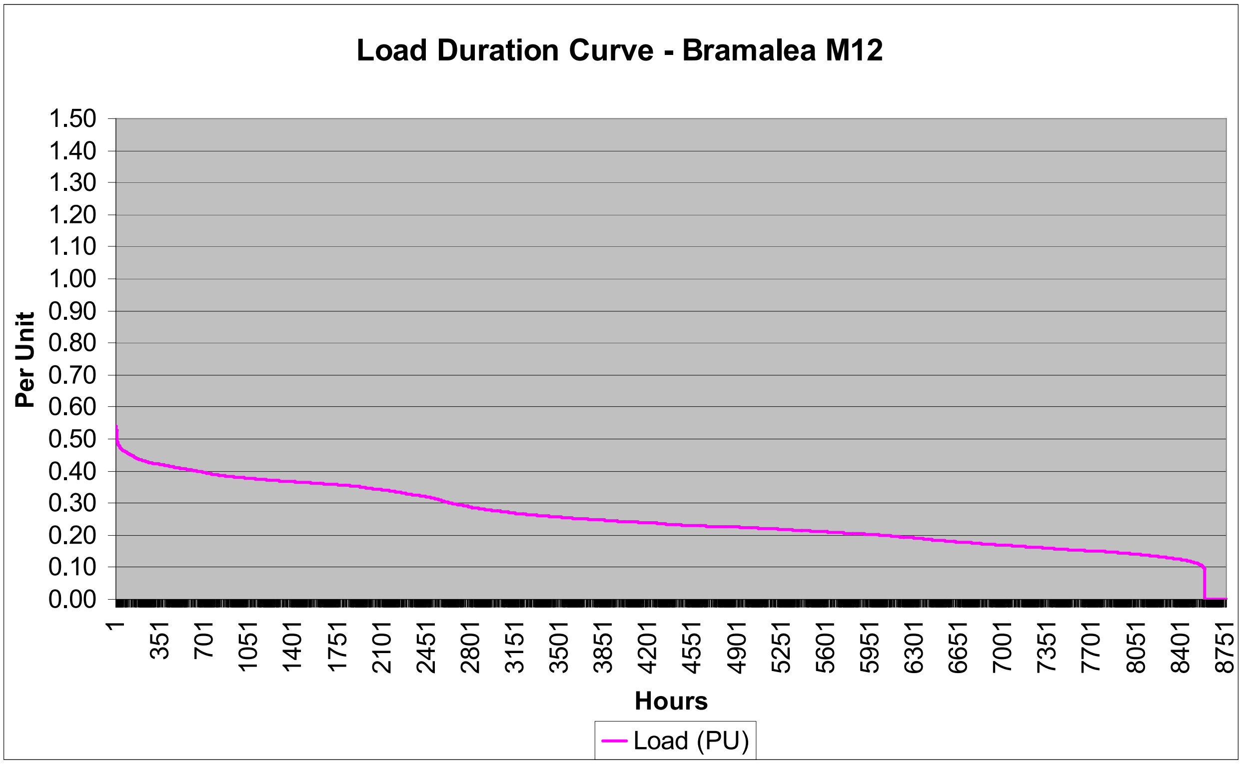


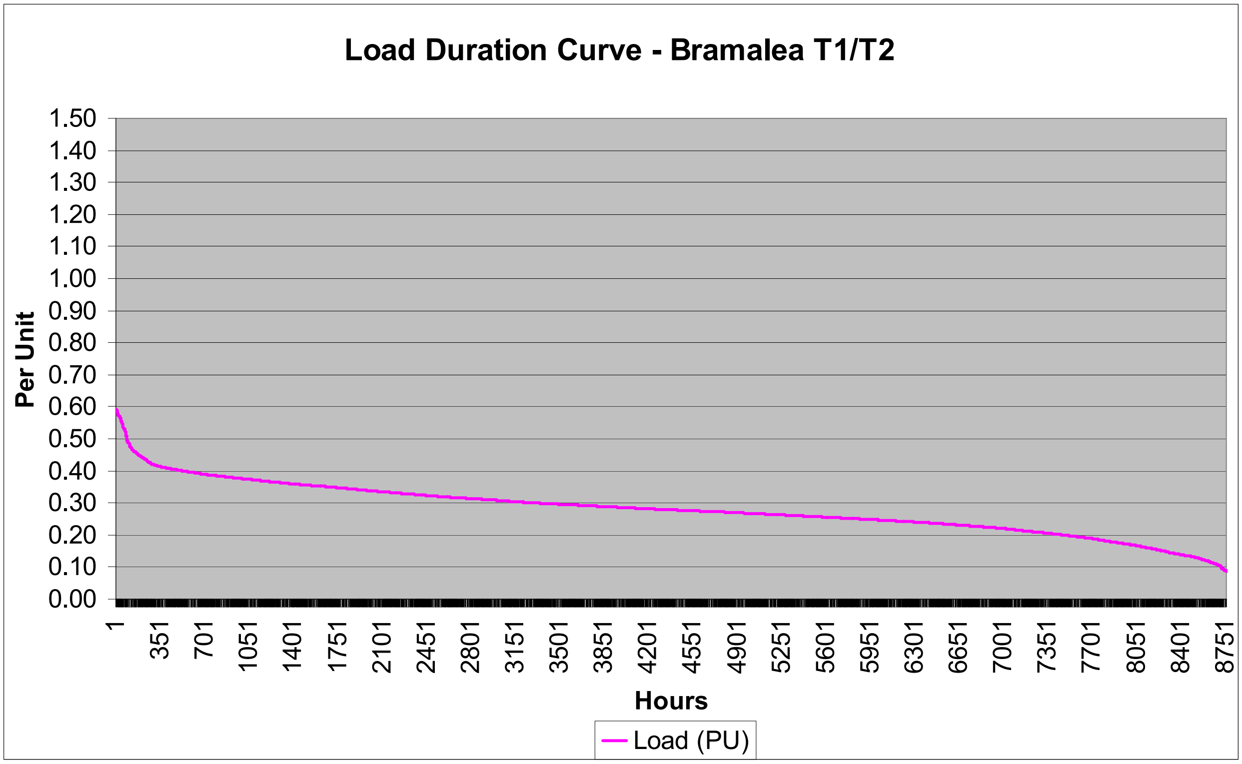



Load Duration Curve - Bramalea M8
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bramalea M9
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

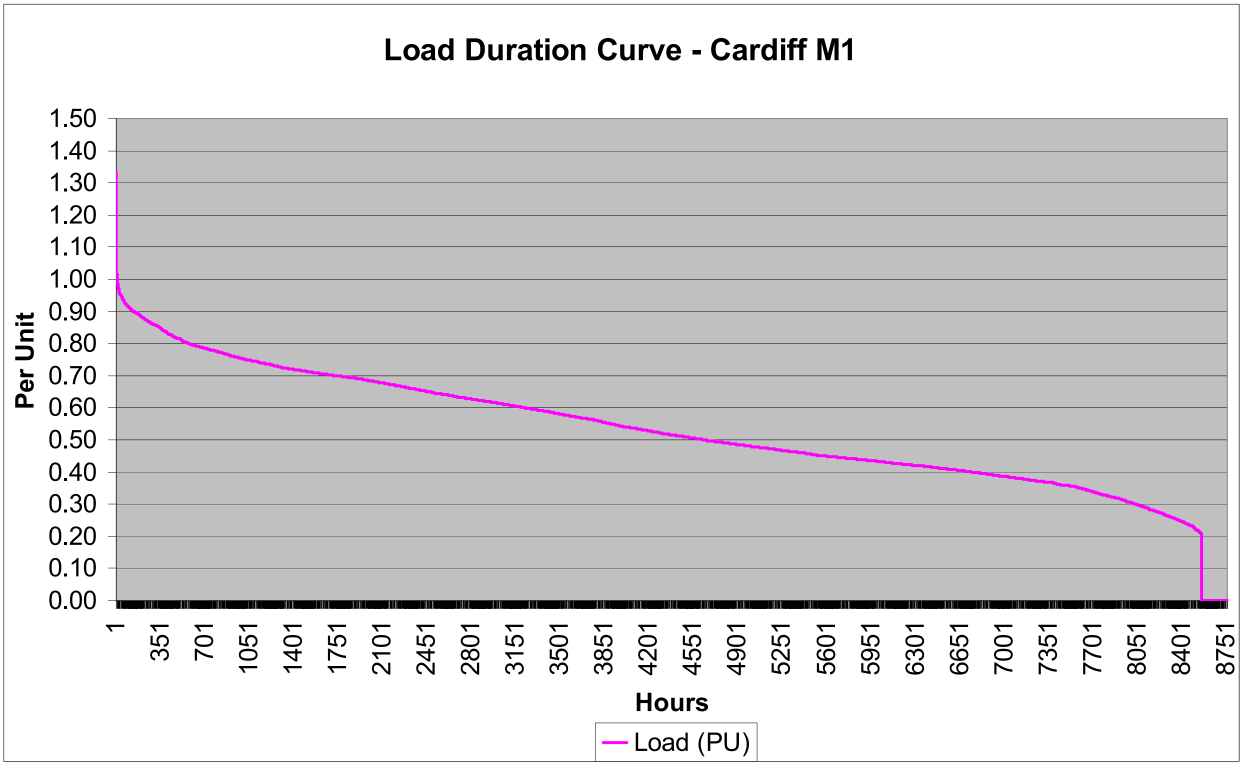

Load Duration Curve - Bramalea M11
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

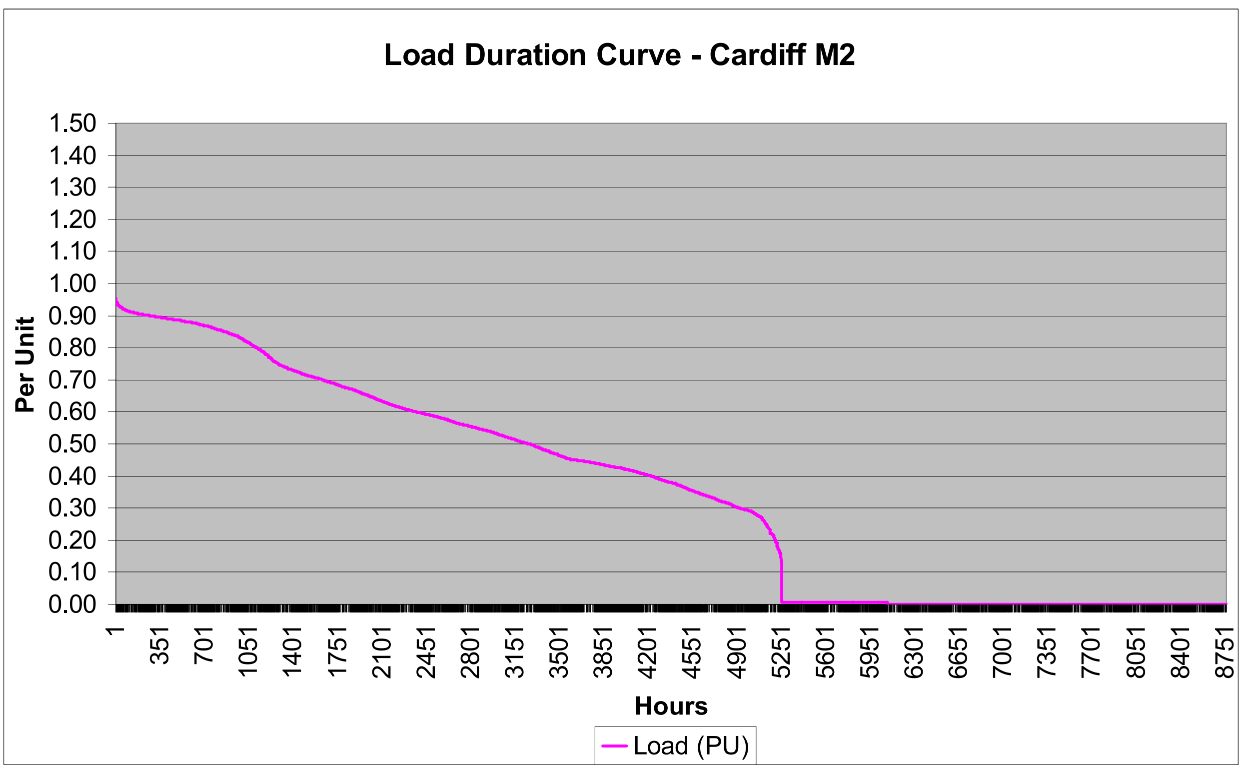

Load Duration Curve - Bramalea M12
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

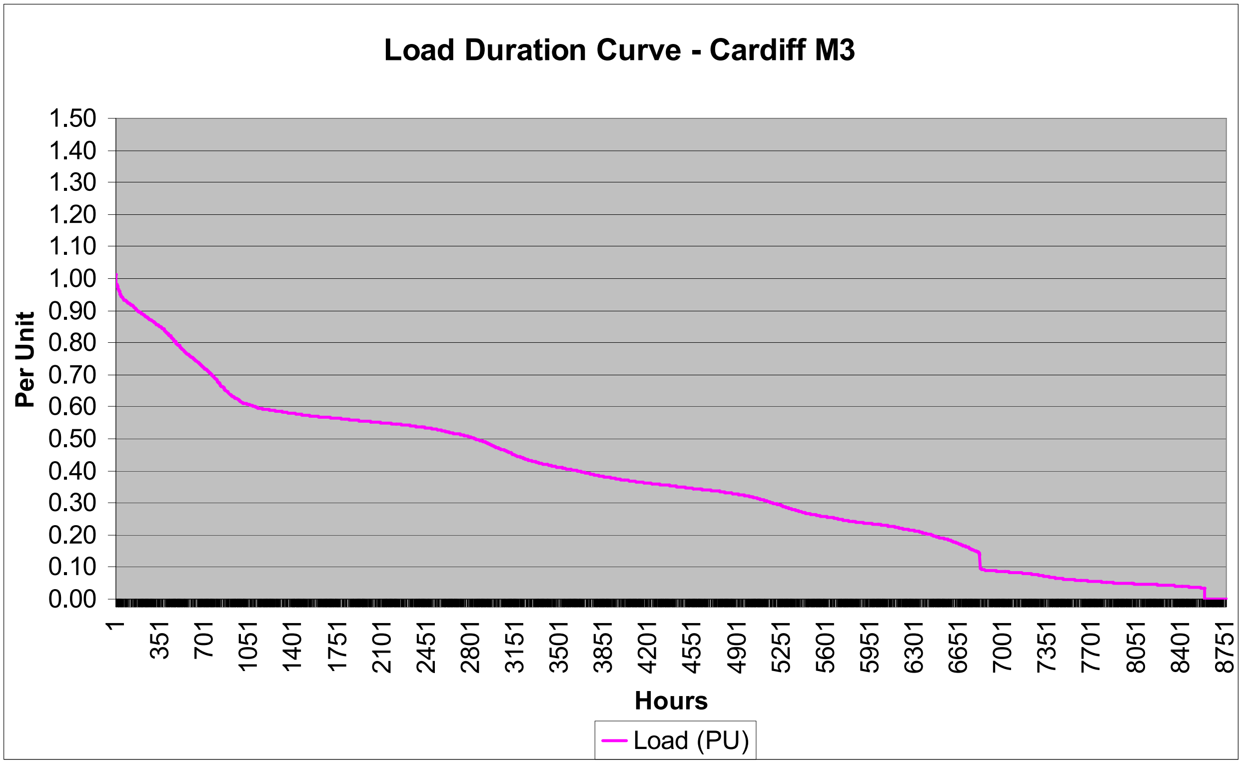


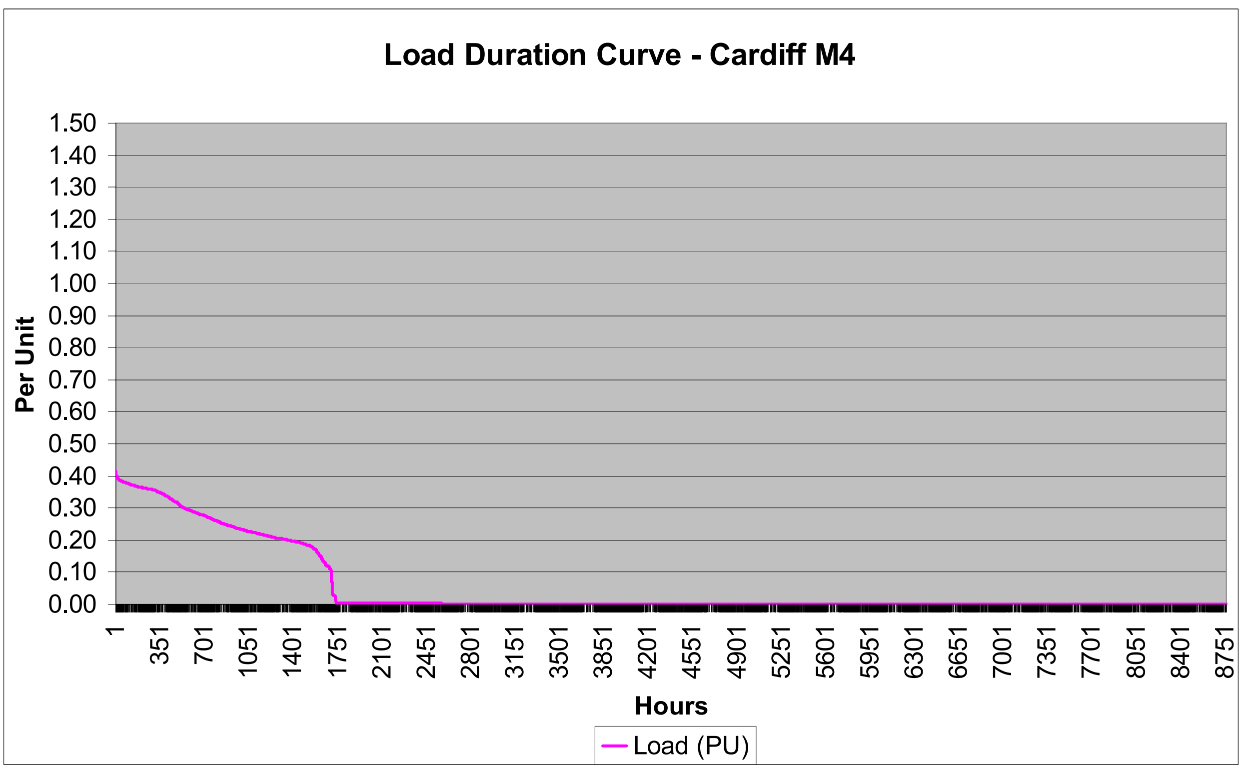
Load Duration Curve - Bramalea T1/T2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

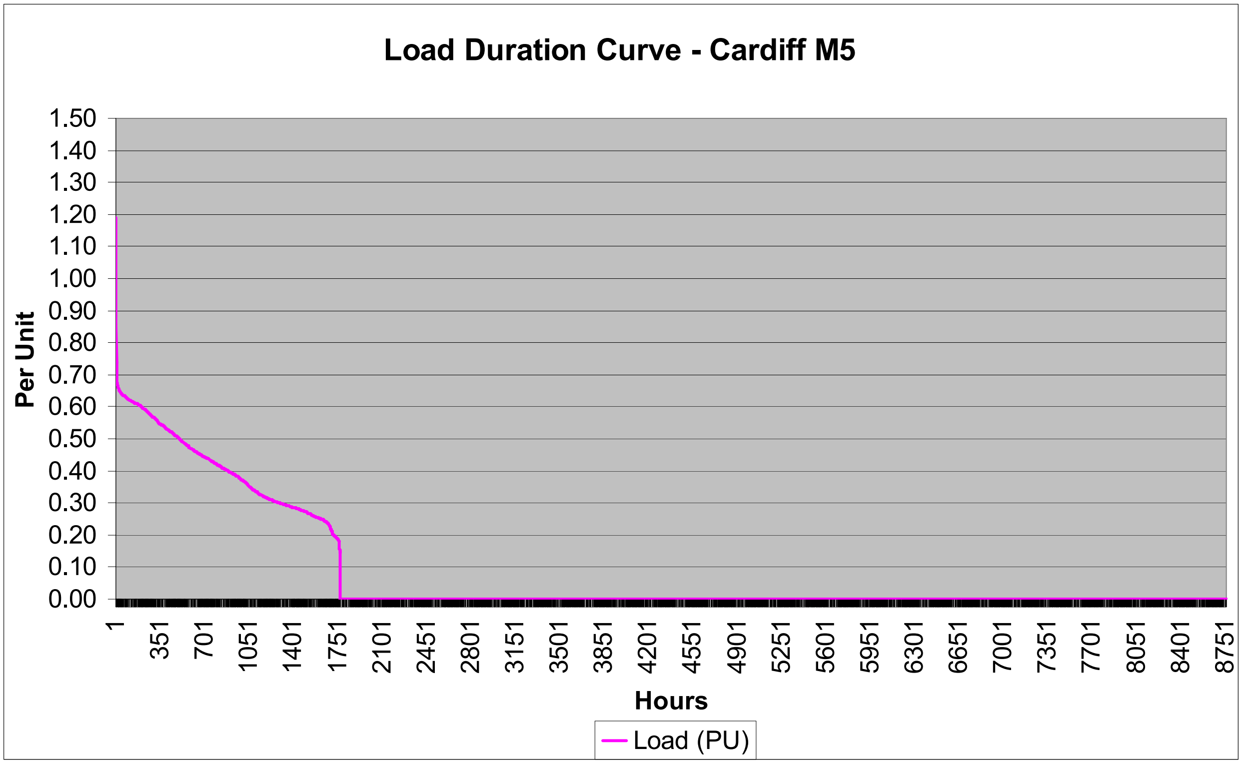
Cardiff TS

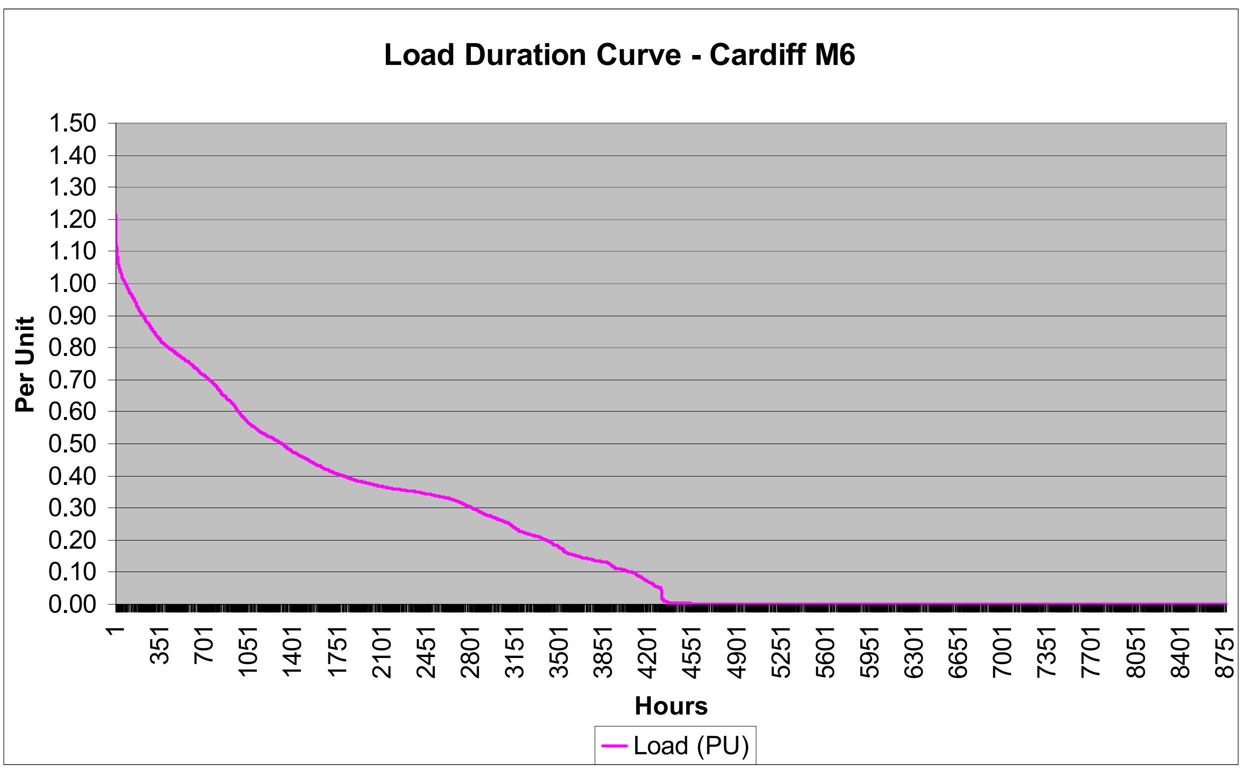

Load Duration Curve - Cardiff M1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

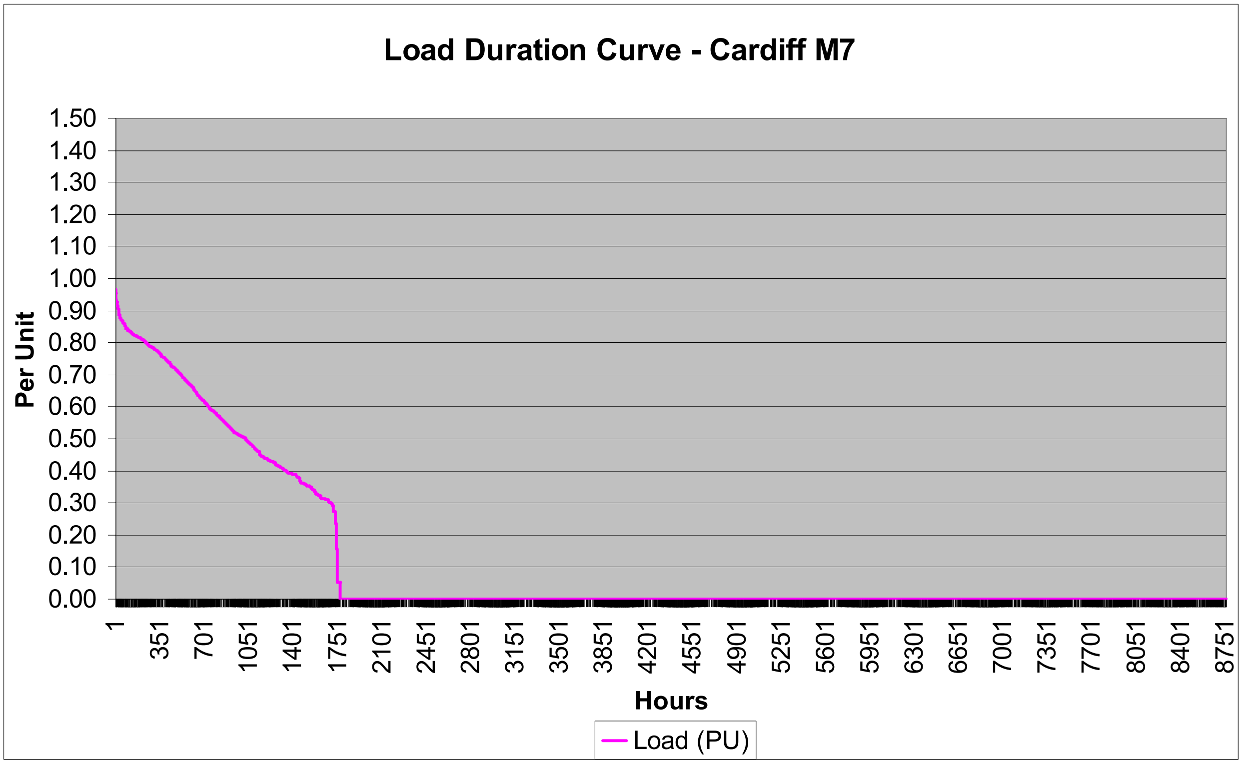

Load Duration Curve - Cardiff M2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

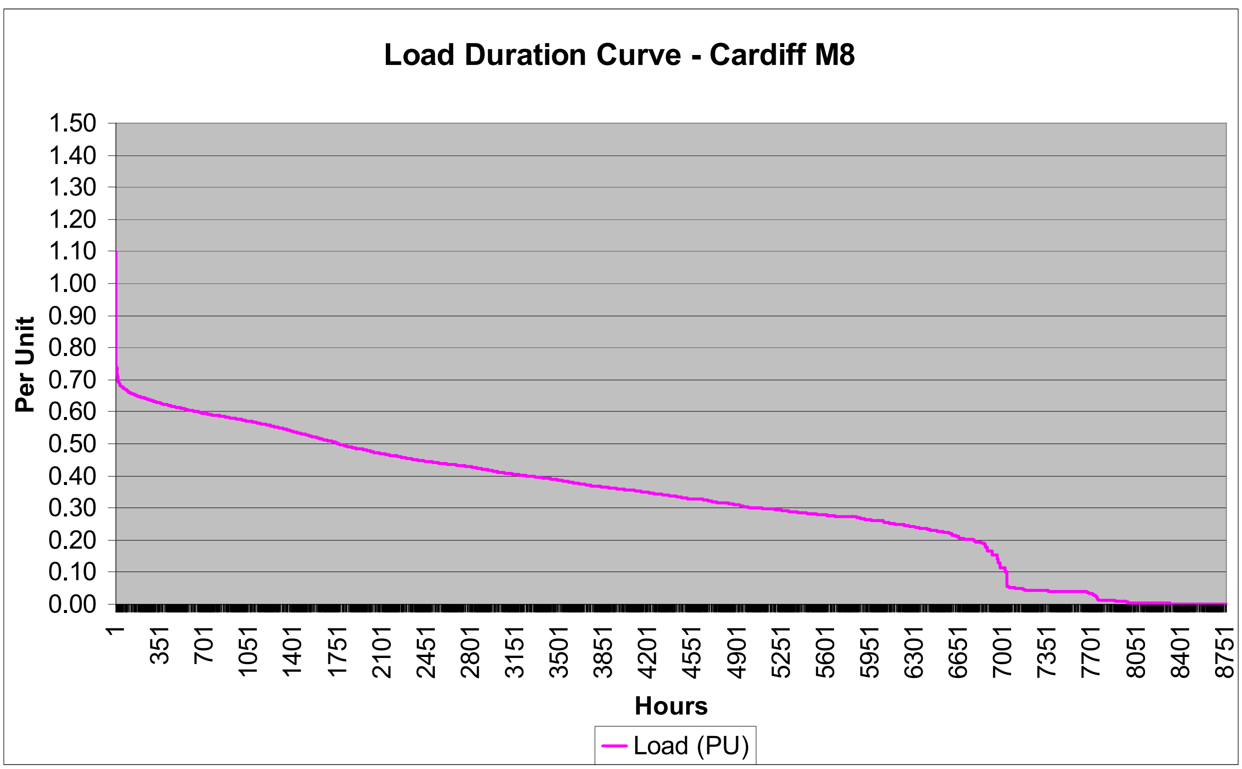

Load Duration Curve - Cardiff M3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

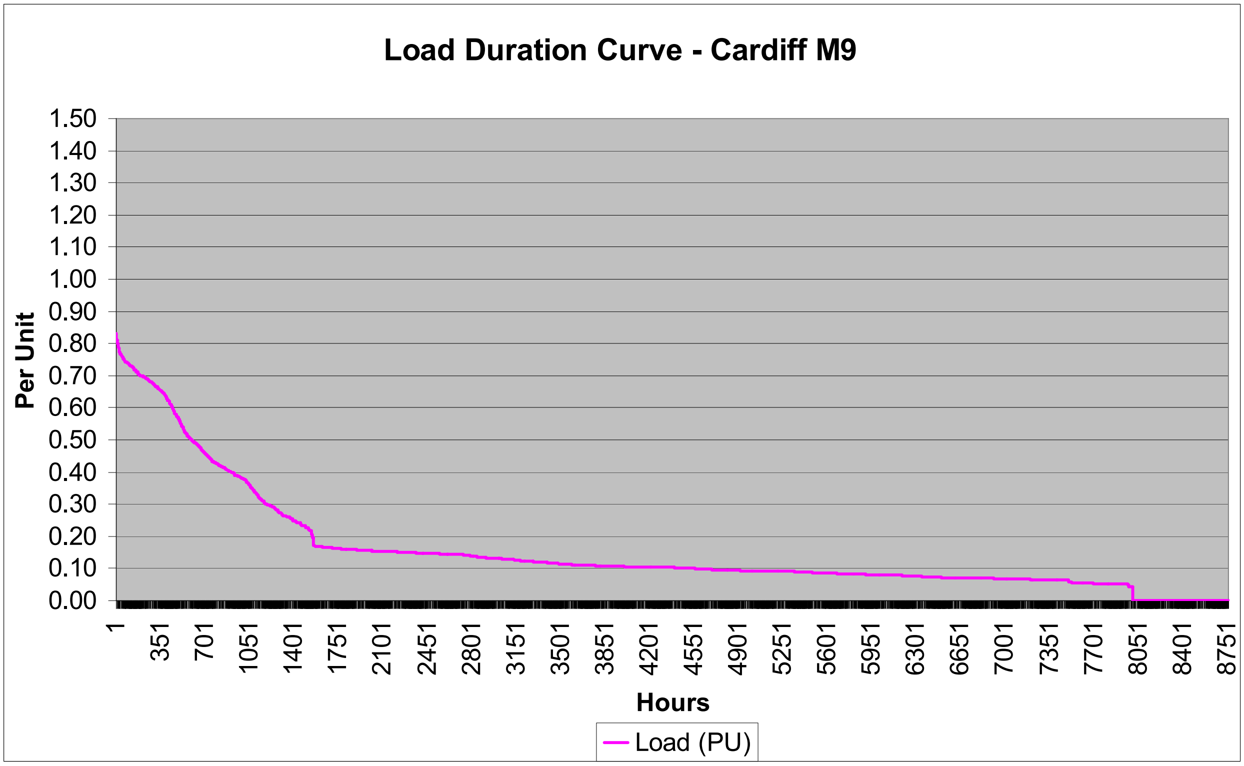

Load Duration Curve - Cardiff M4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

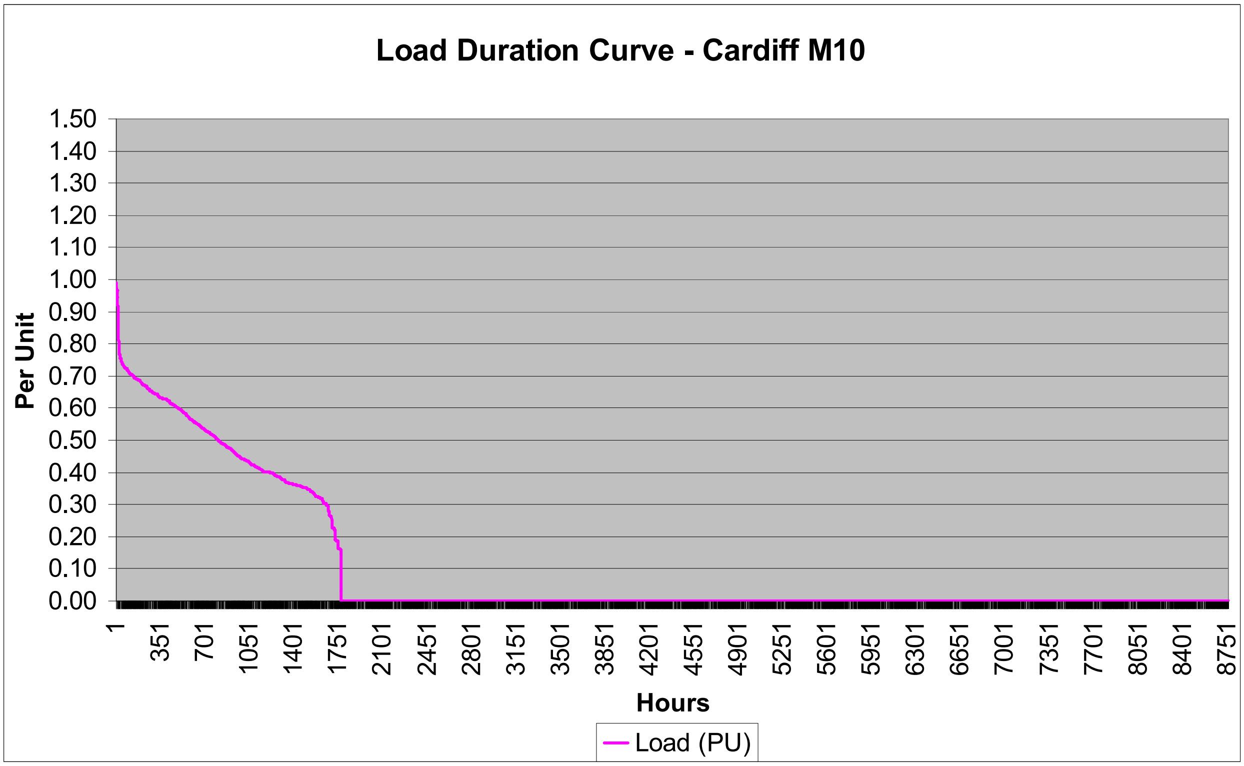

Load Duration Curve - Cardiff M5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

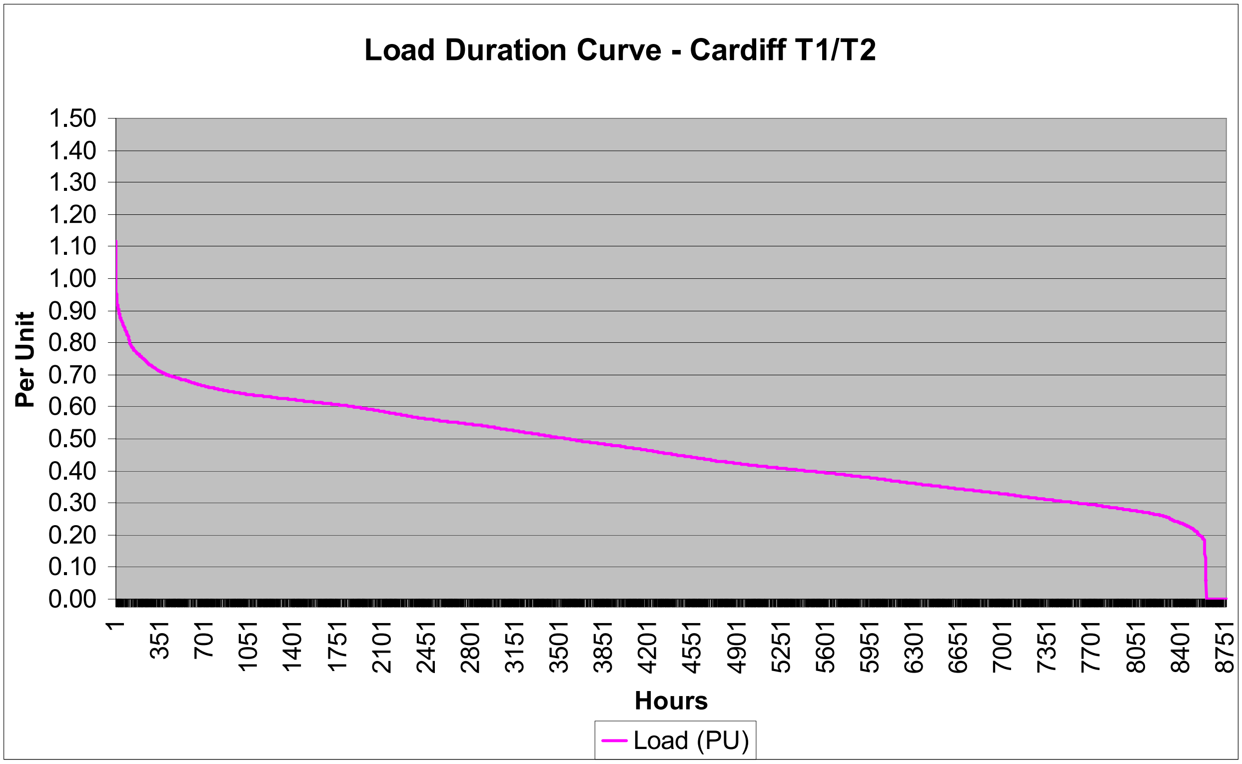

Load Duration Curve - Cardiff M6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cardiff M7
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cardiff M8
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cardiff M9
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Cardiff M10
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Cardiff T1/T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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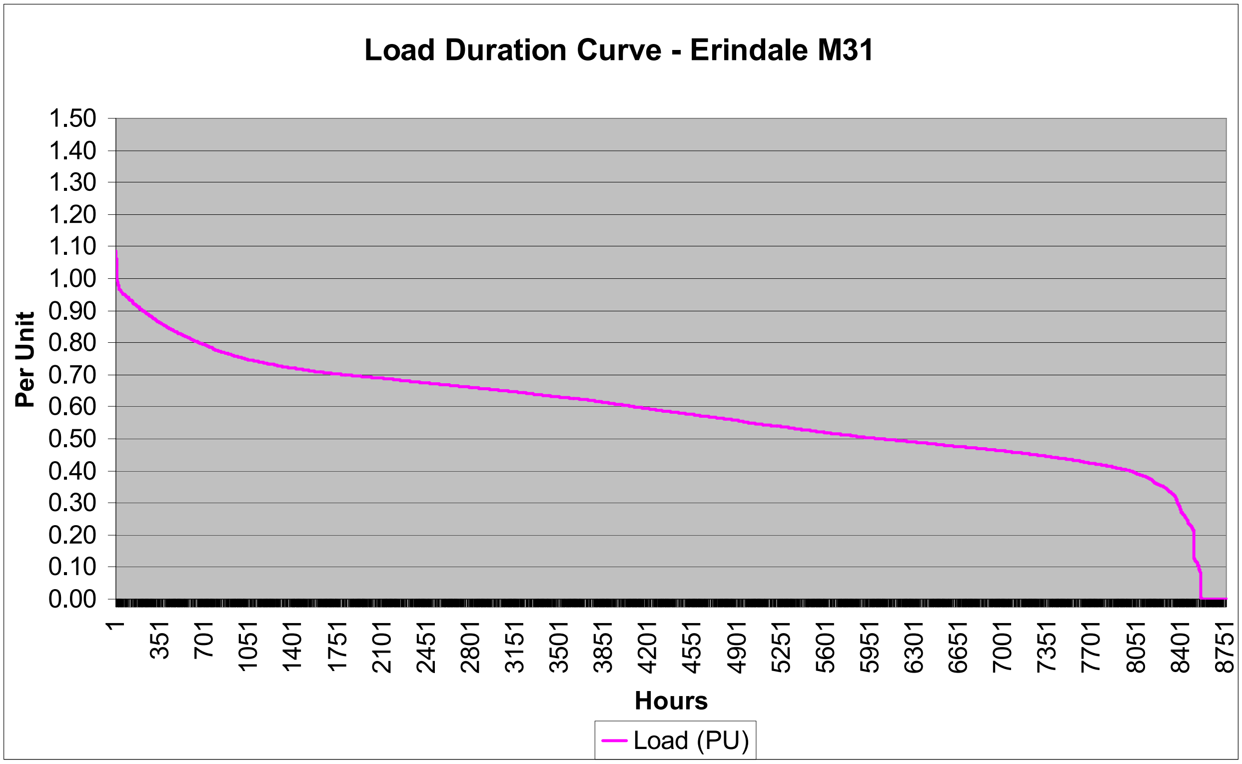
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Erindale TS



Load Duration Curve - Erindale M31
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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6301
6651
7001
7351
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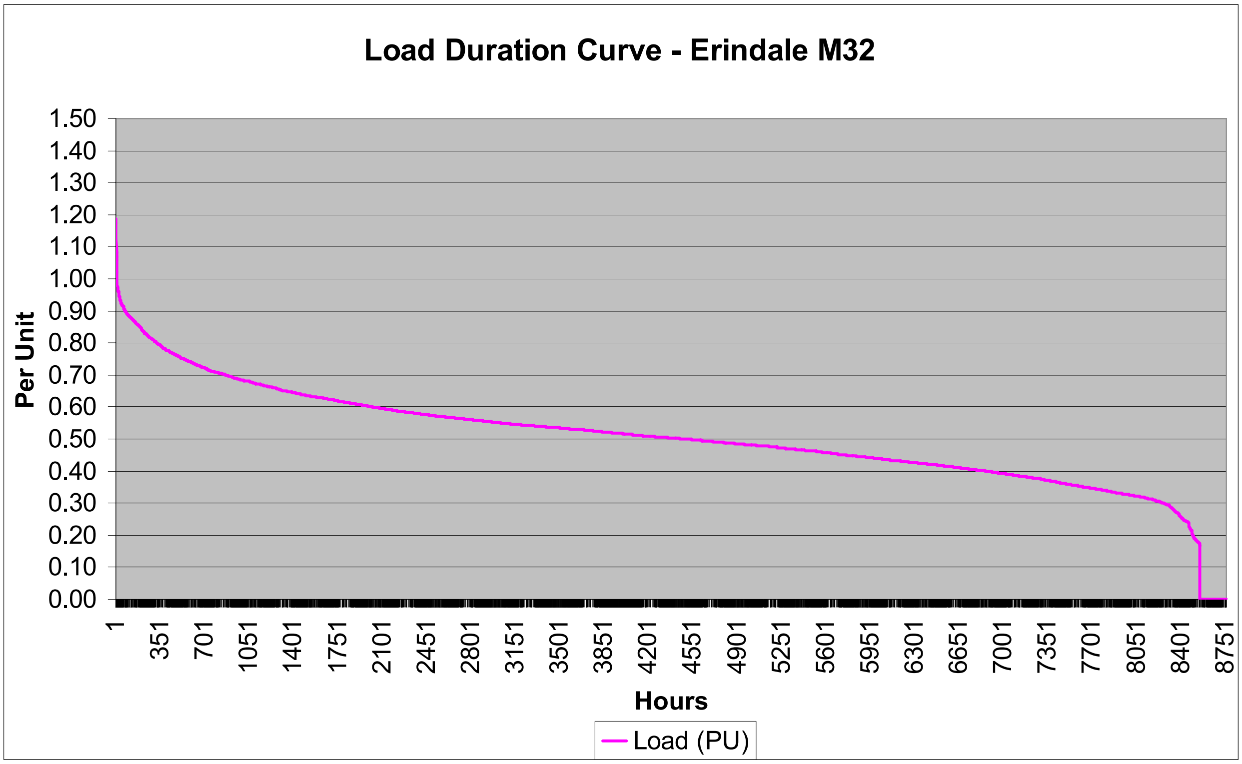
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Erindale M32
1.50
1.40
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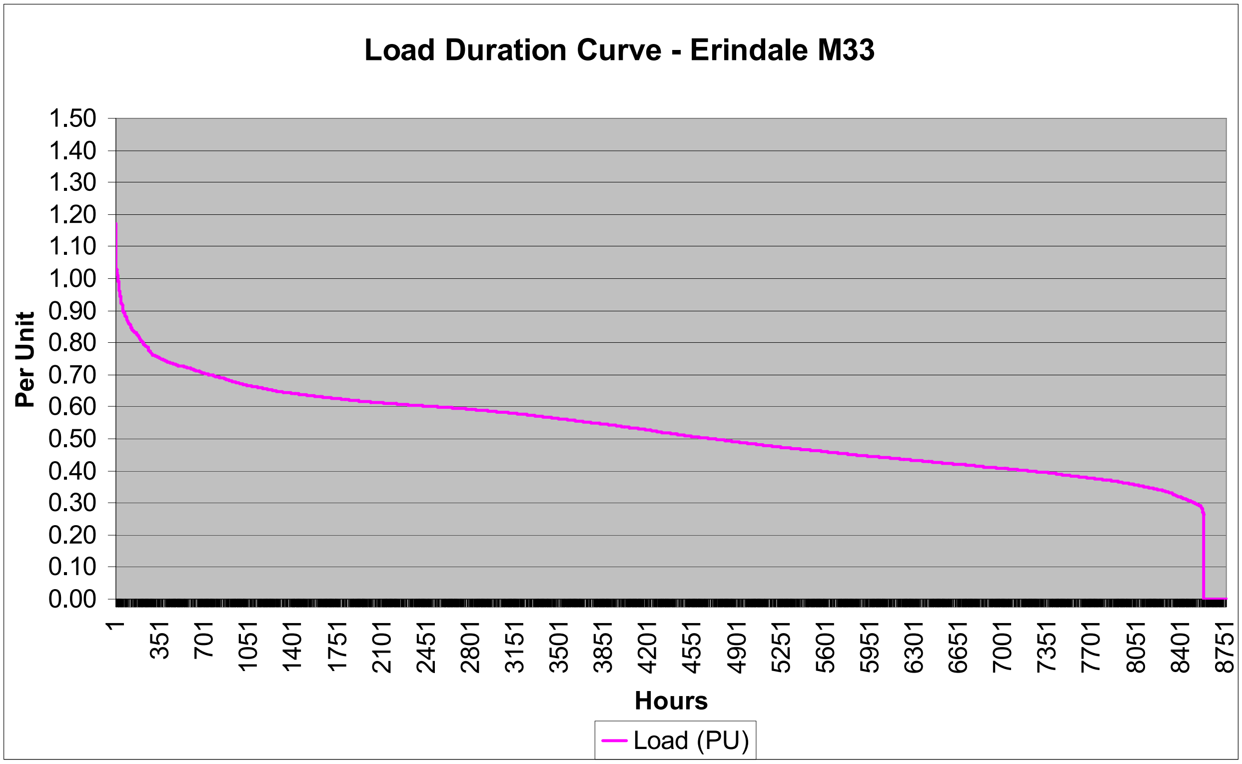
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M33
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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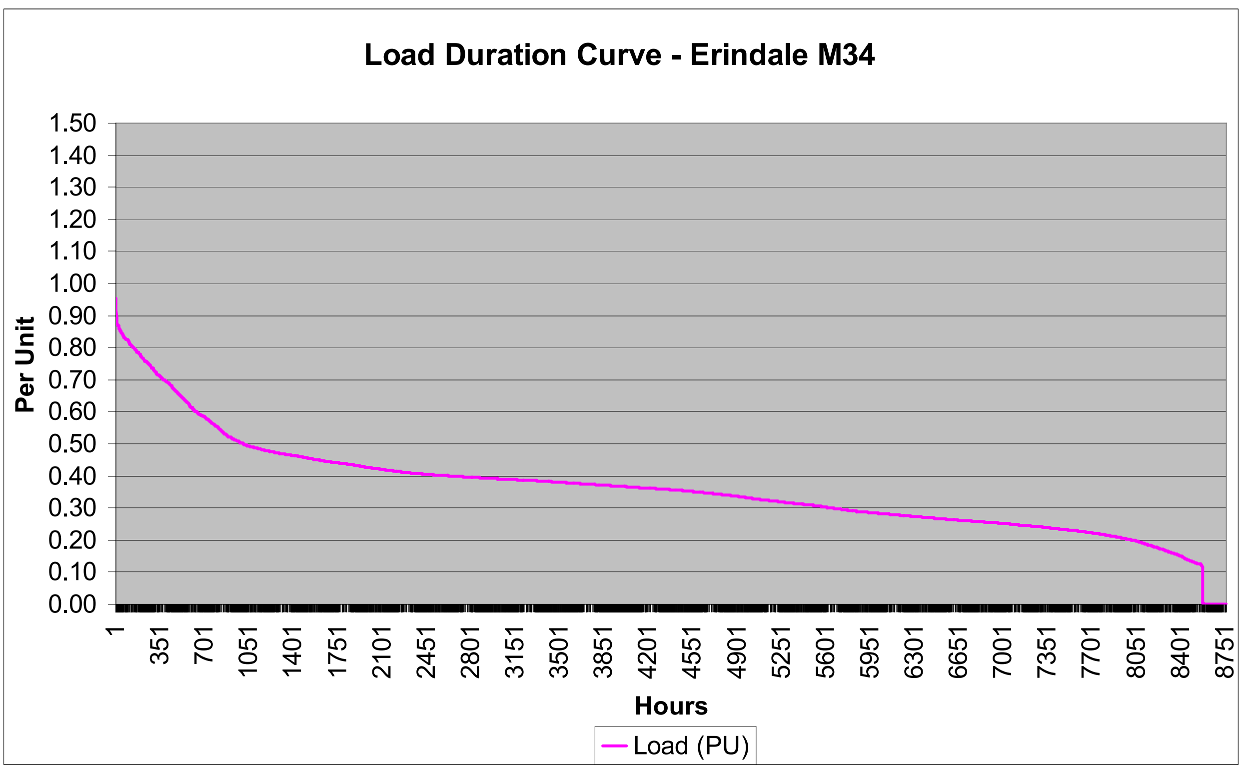
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M34
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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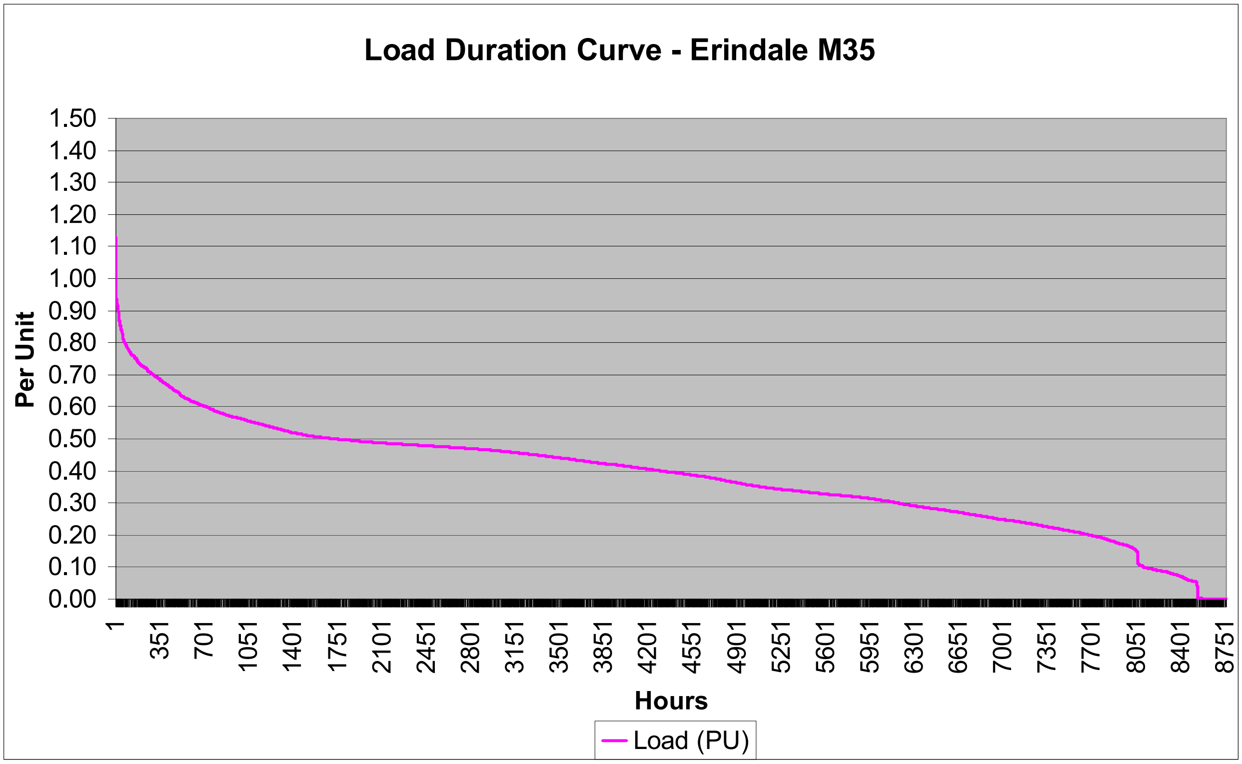
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M35
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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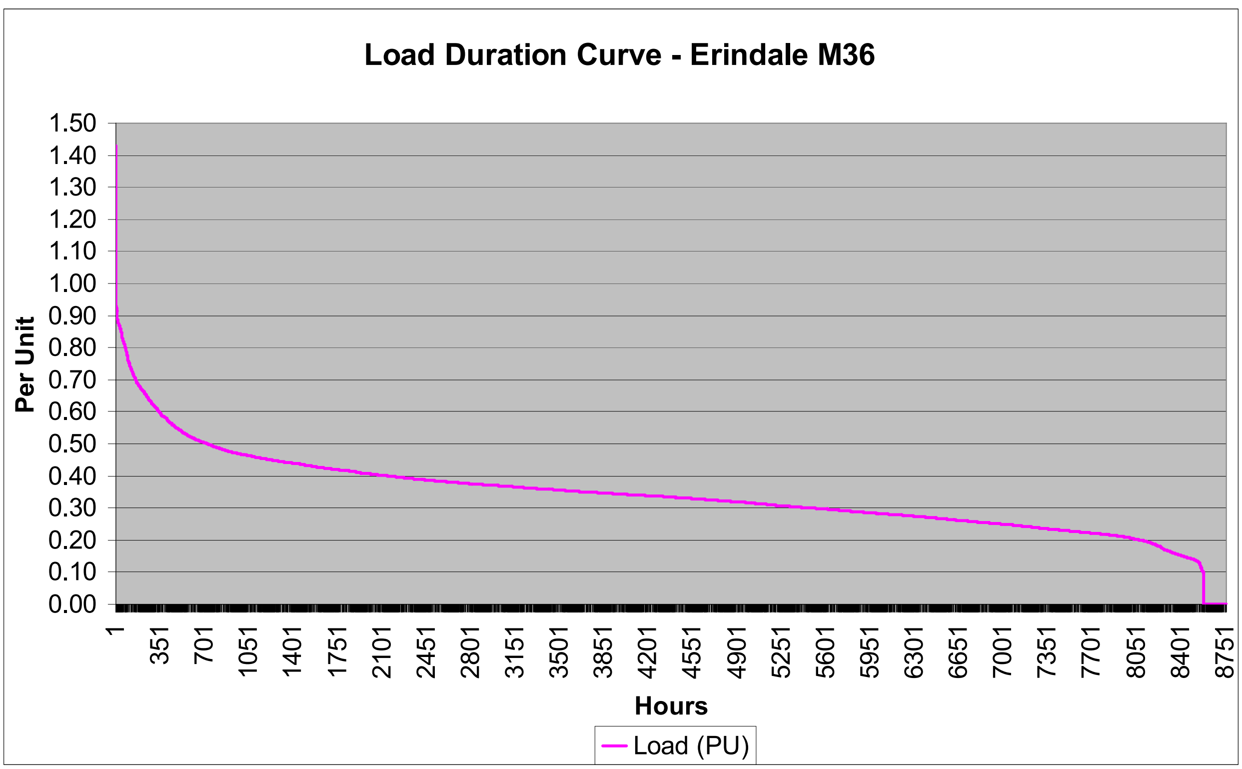
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M36
Per Unit
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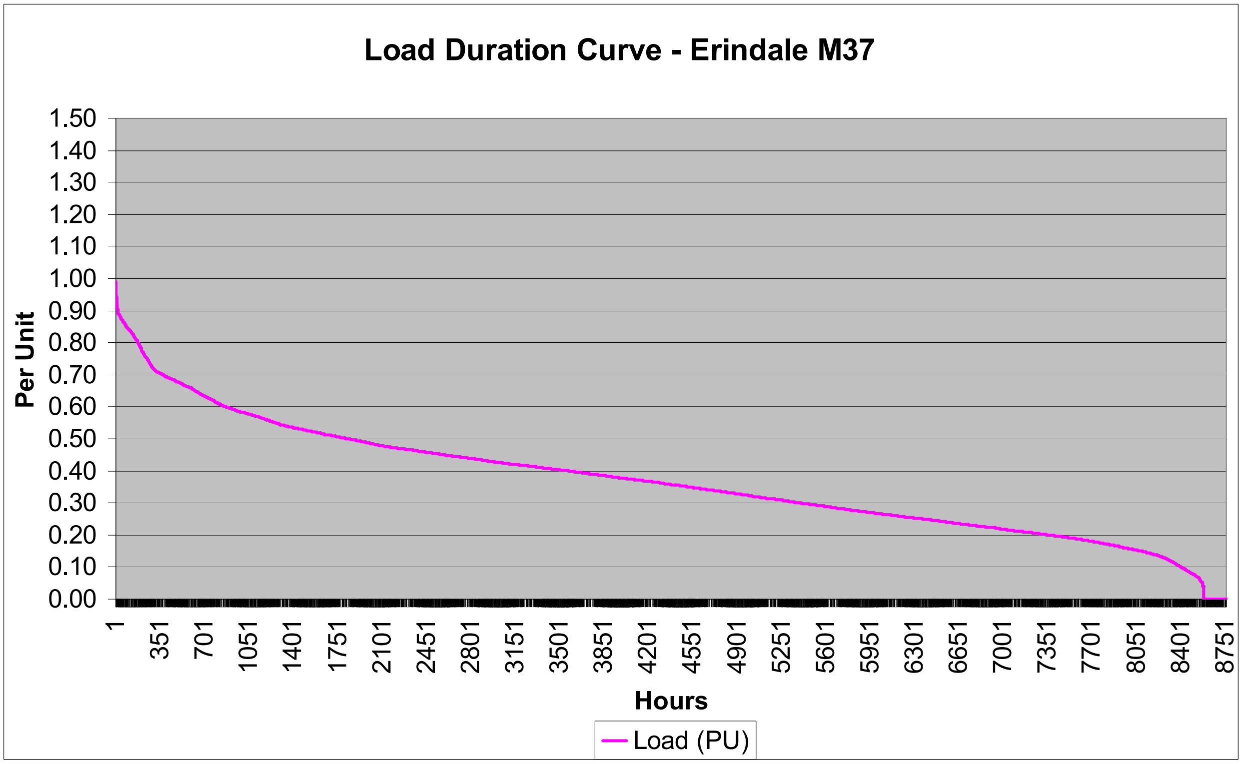
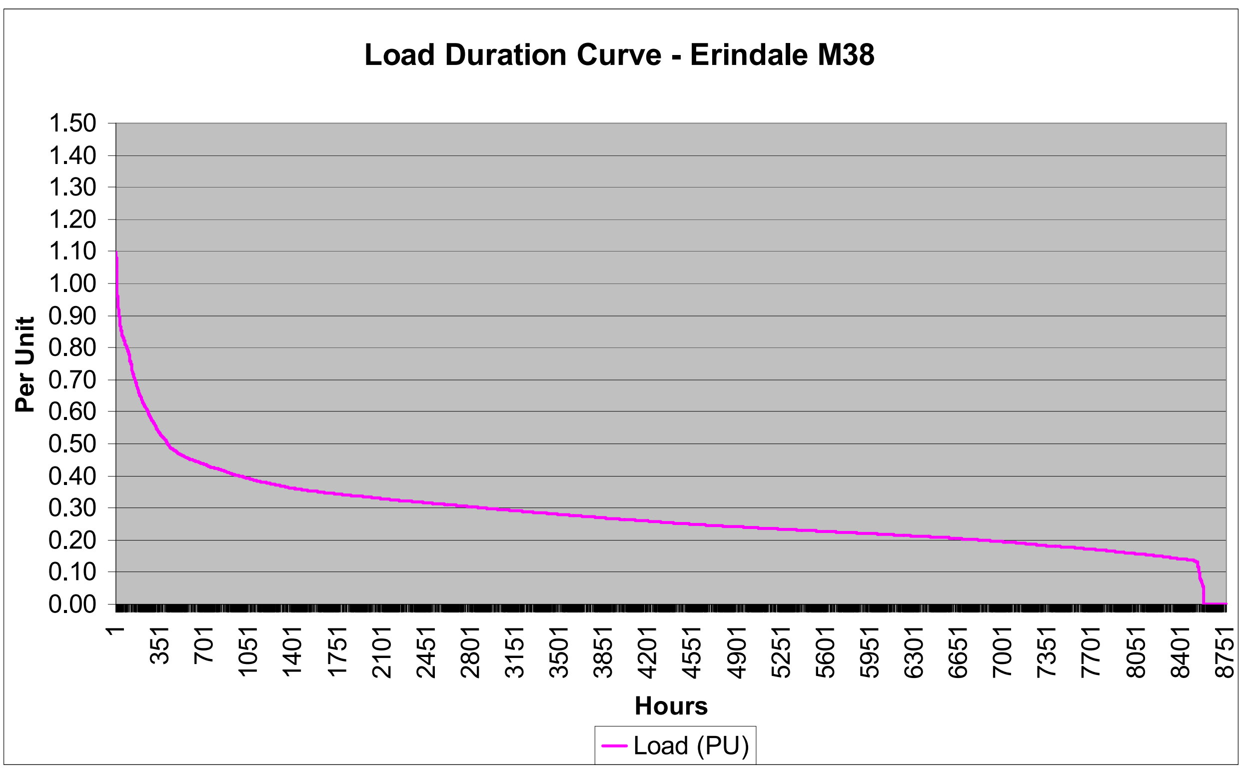
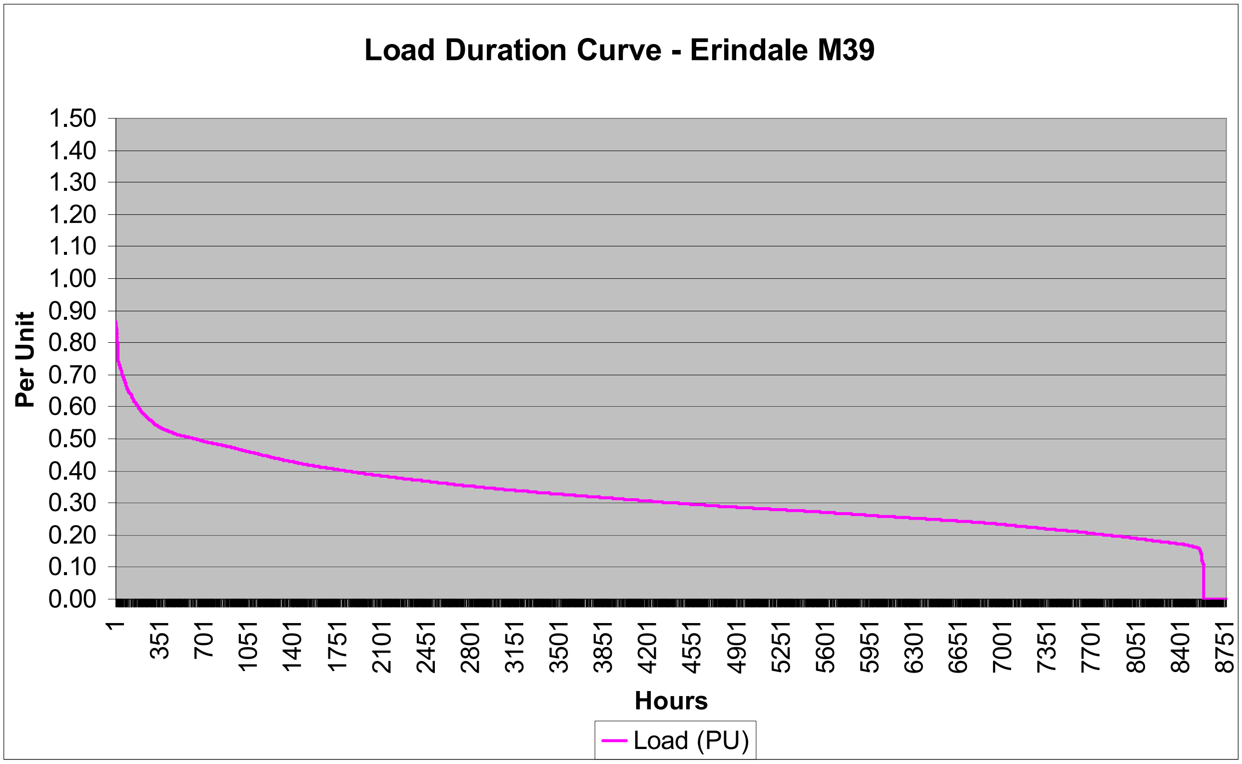
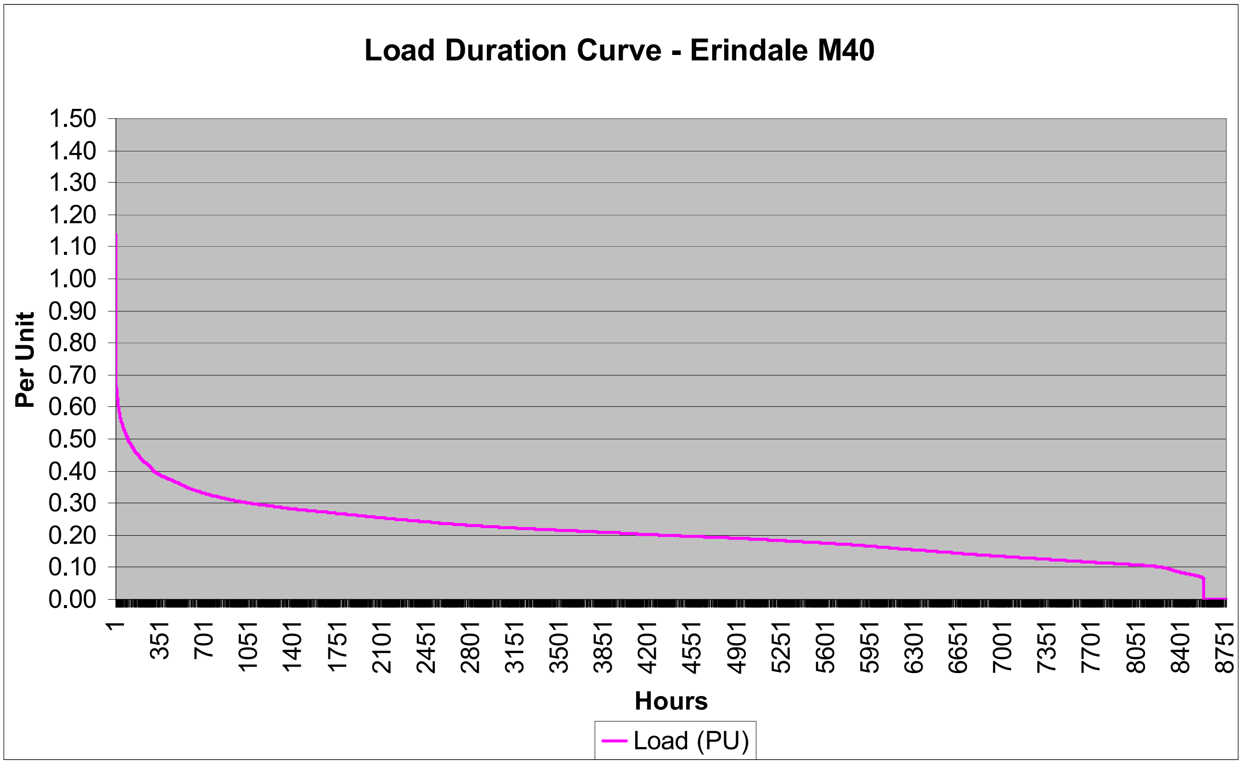
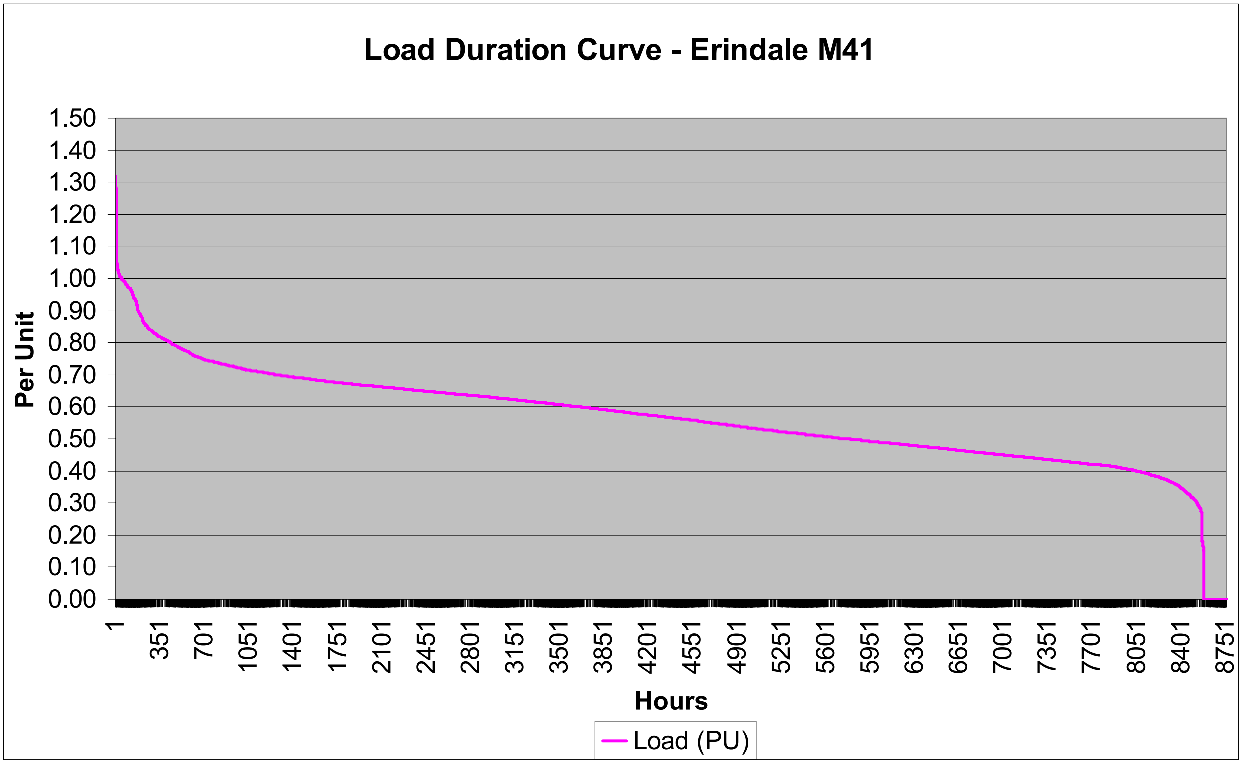
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

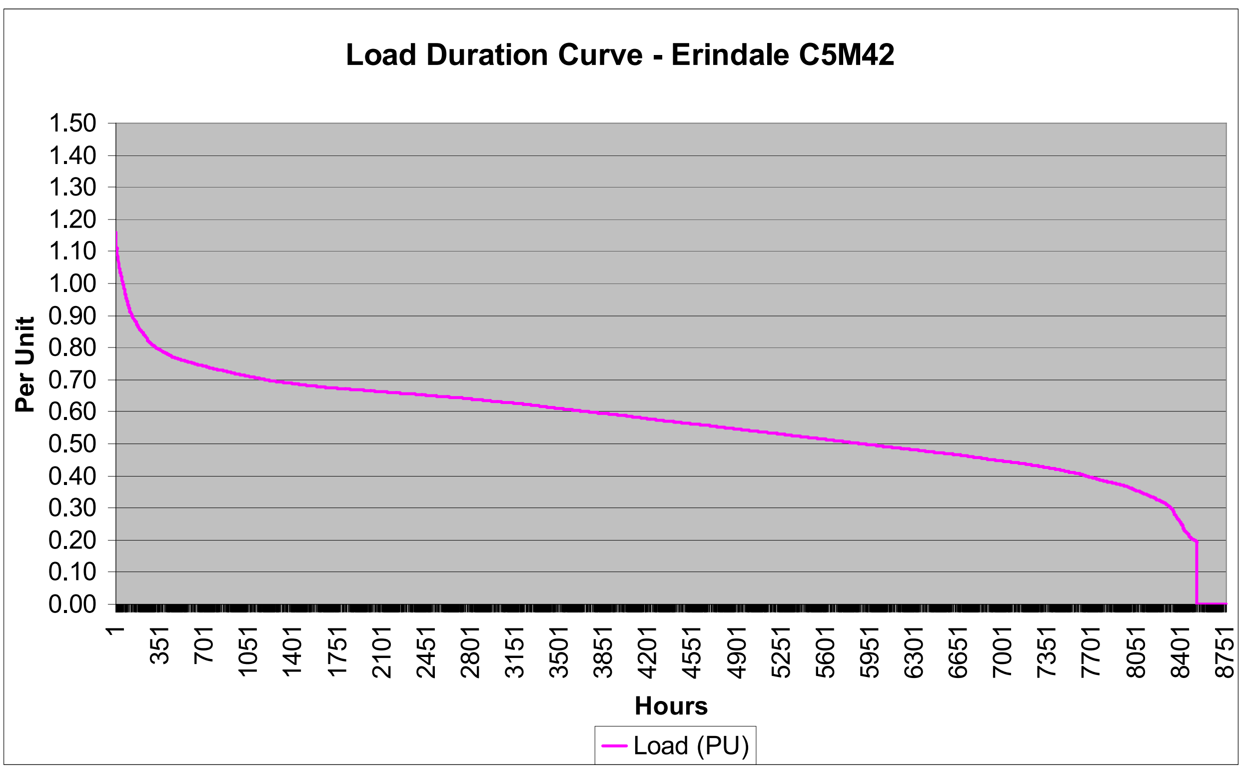

Load Duration Curve - Erindale M37
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

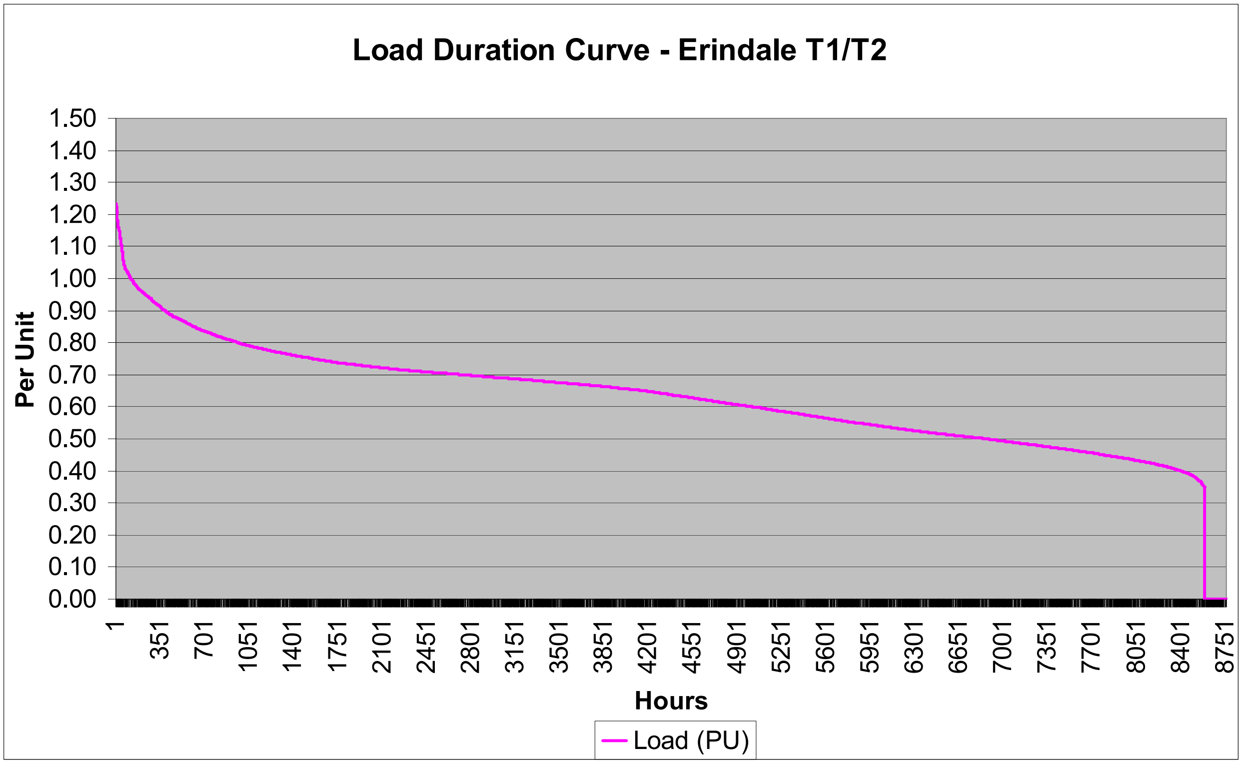

Load Duration Curve - Erindale M38
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M39
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M40
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

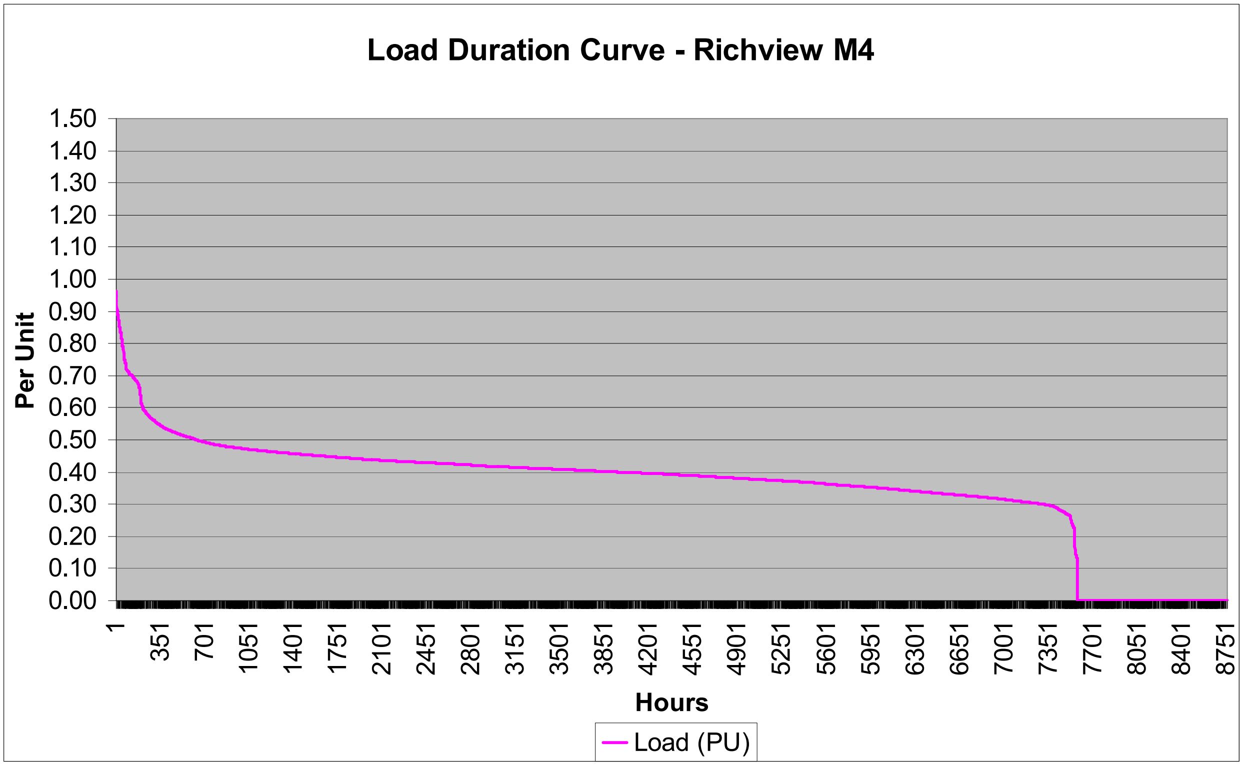

Load Duration Curve - Erindale M41
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale C5M42
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Erindale T1/T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Richview TS


Load Duration Curve - Richview M4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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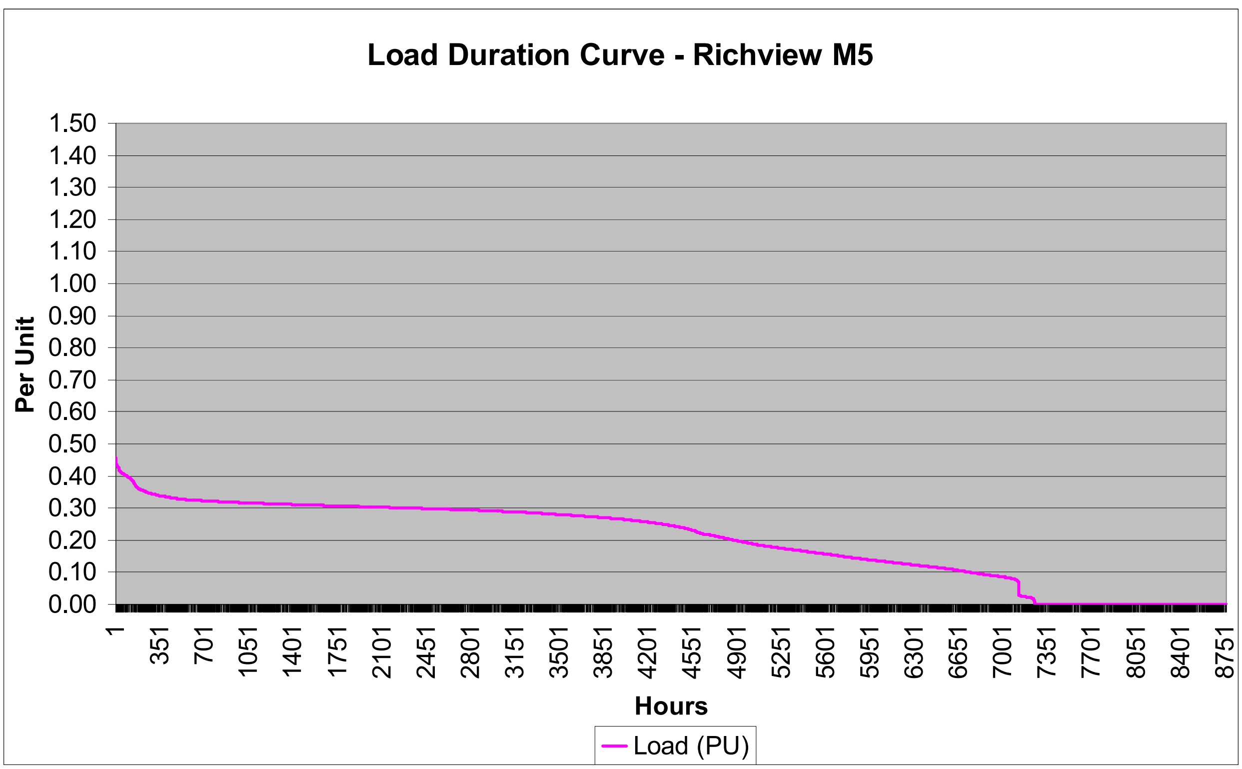
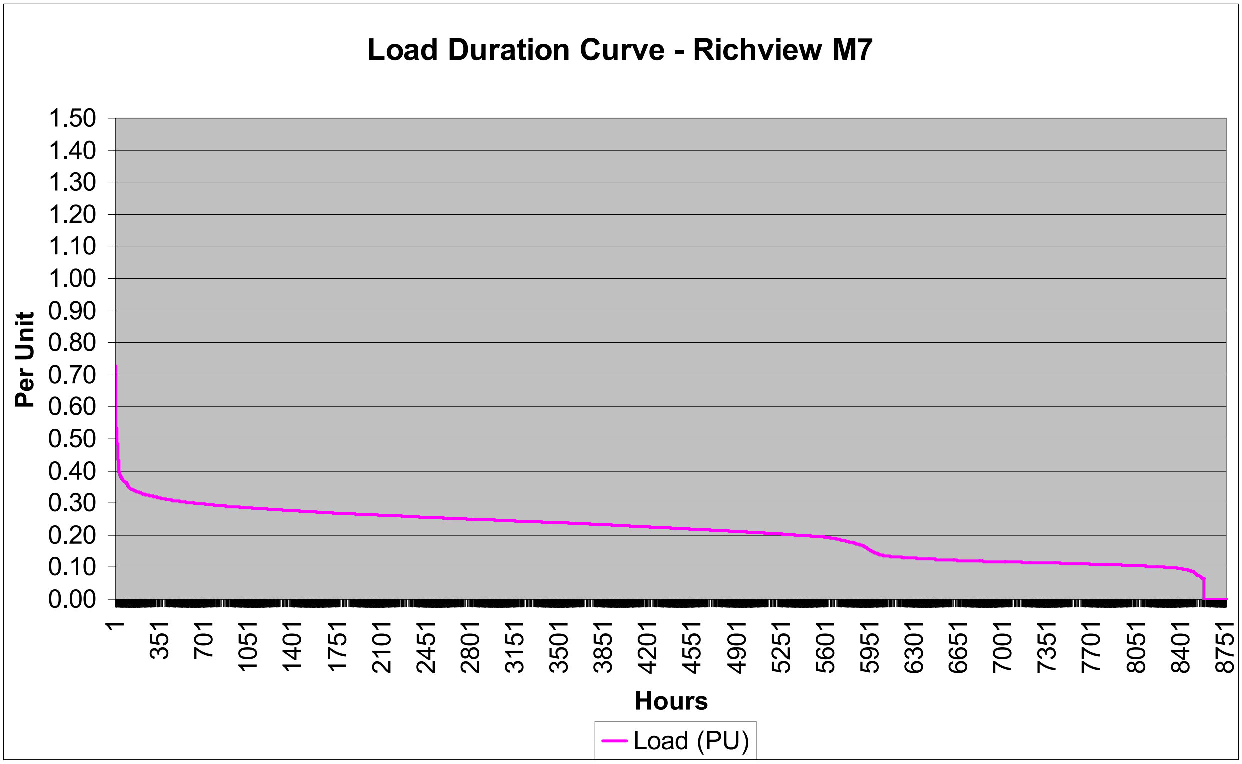
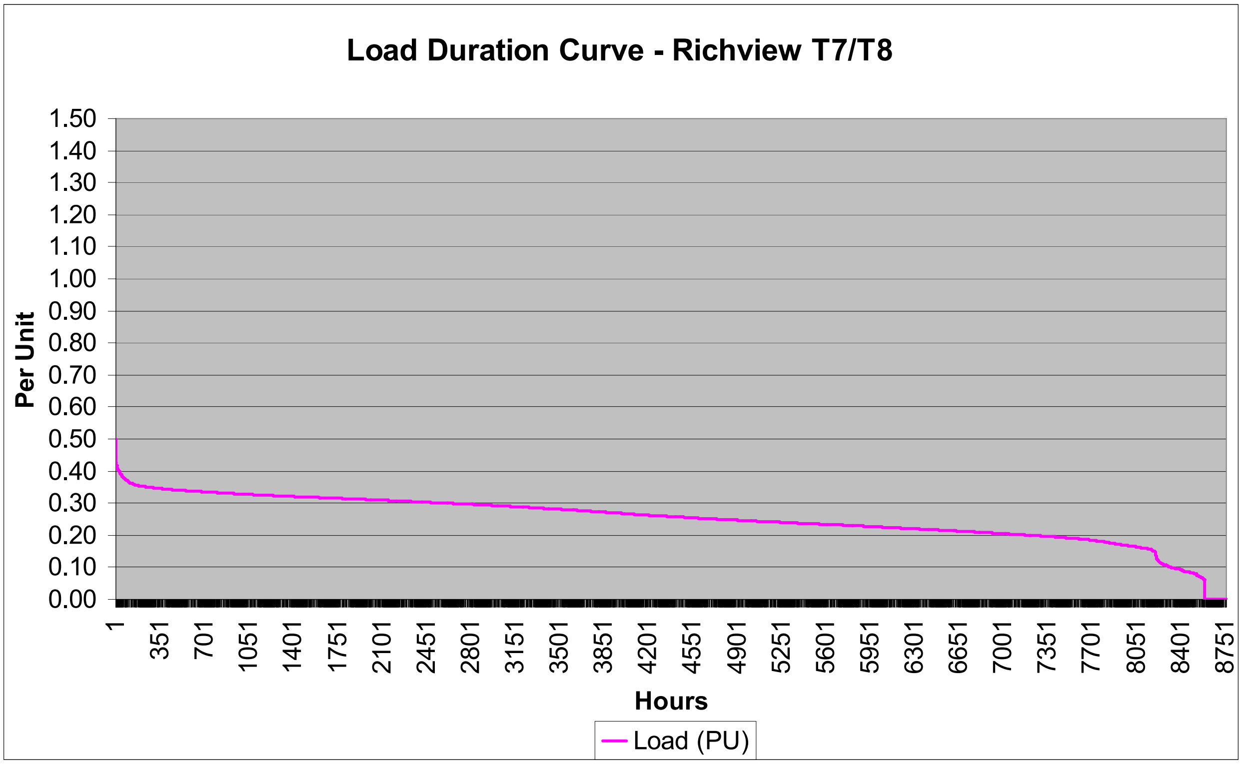
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Richview M5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Richview M7
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Richview T7/T8
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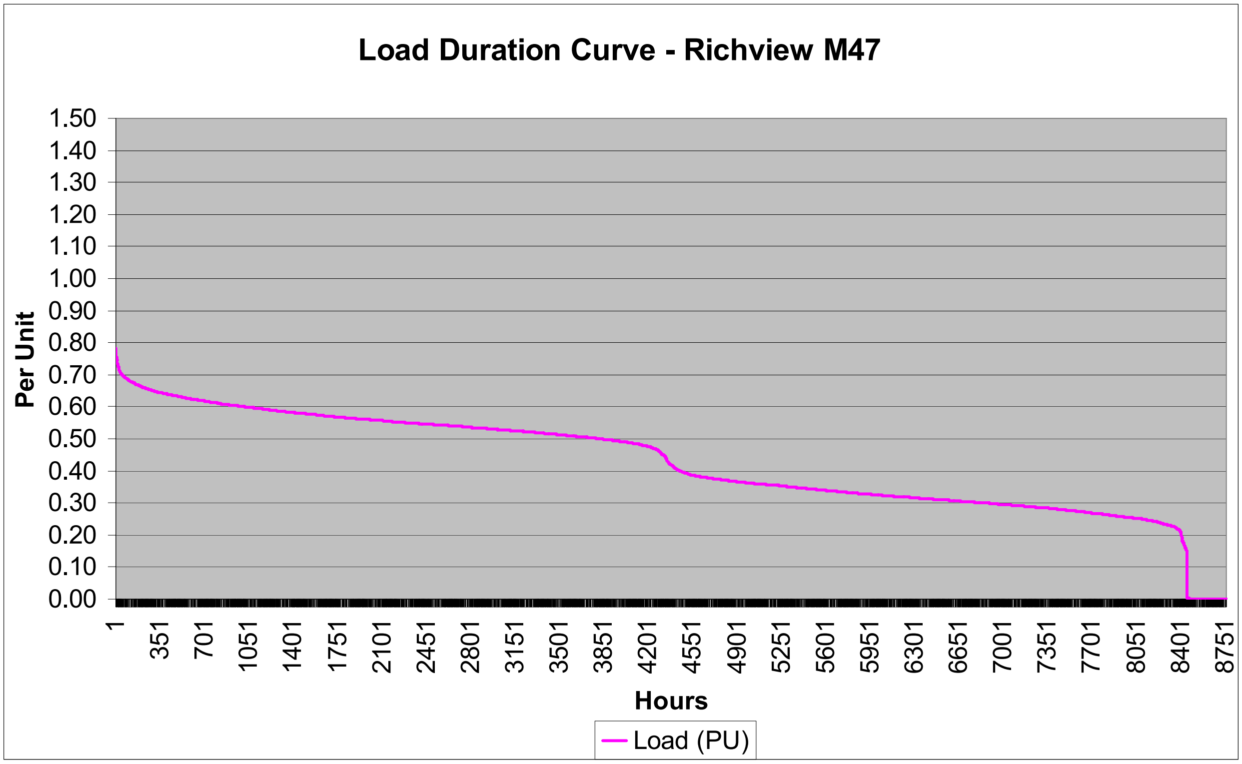
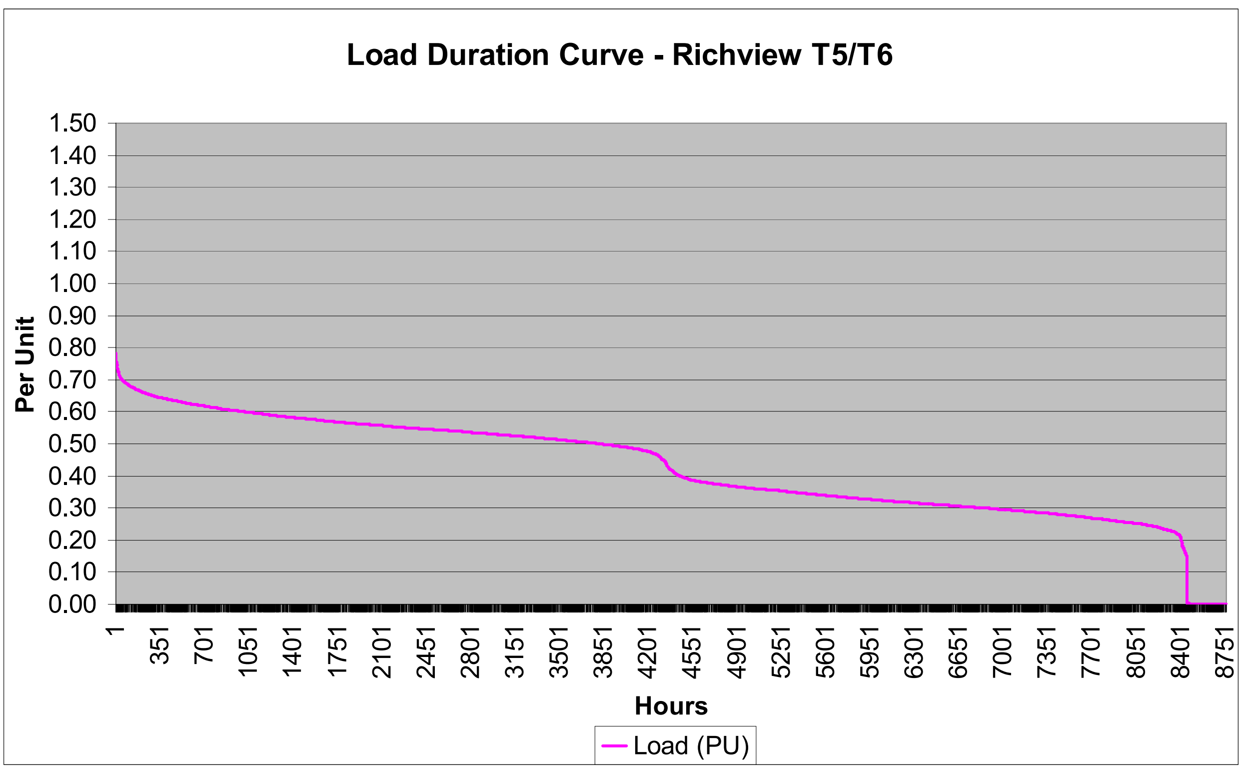
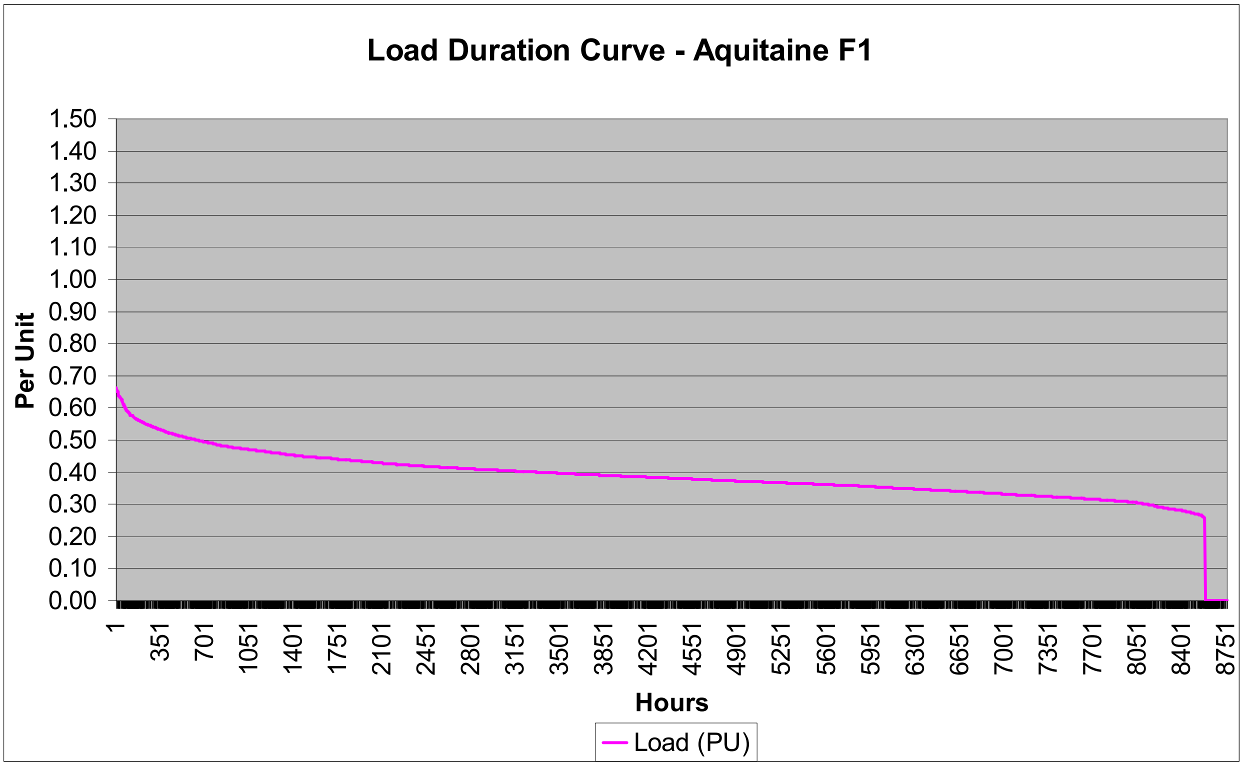
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

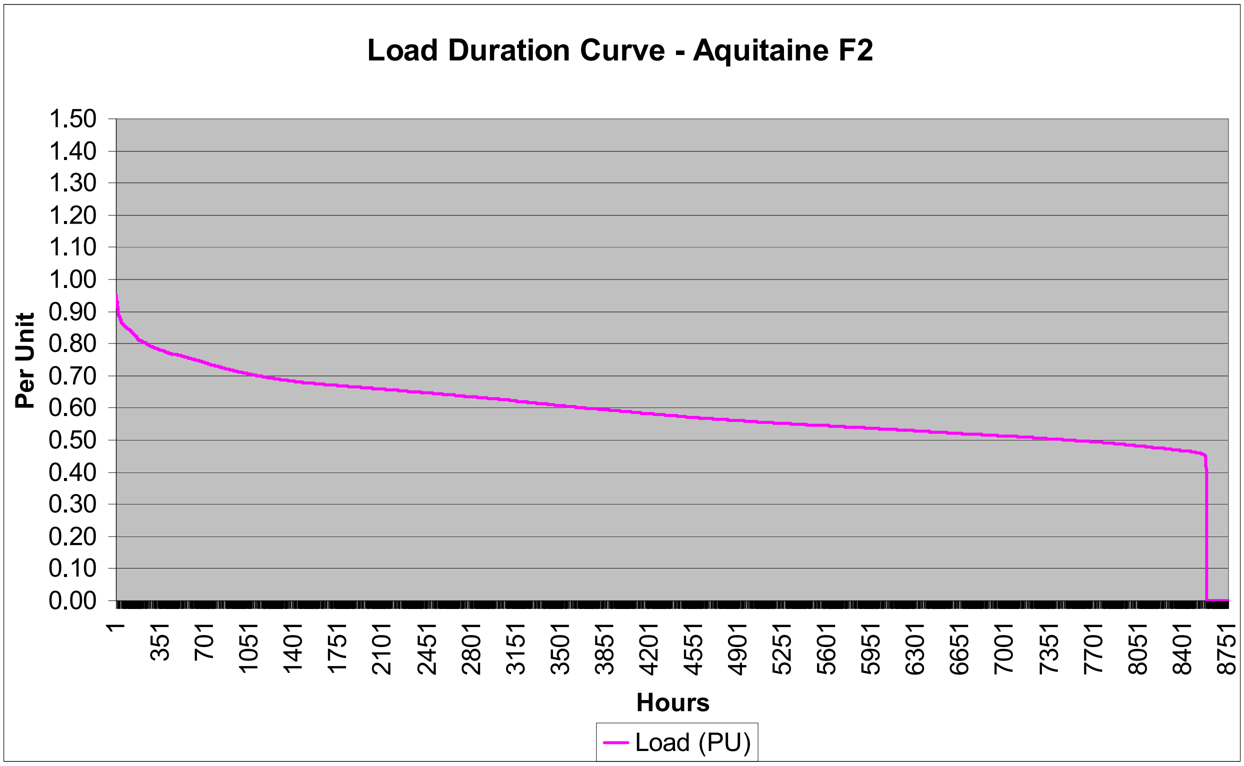

Load Duration Curve - Richview M47
Per Unit
Hours
Load (PU)

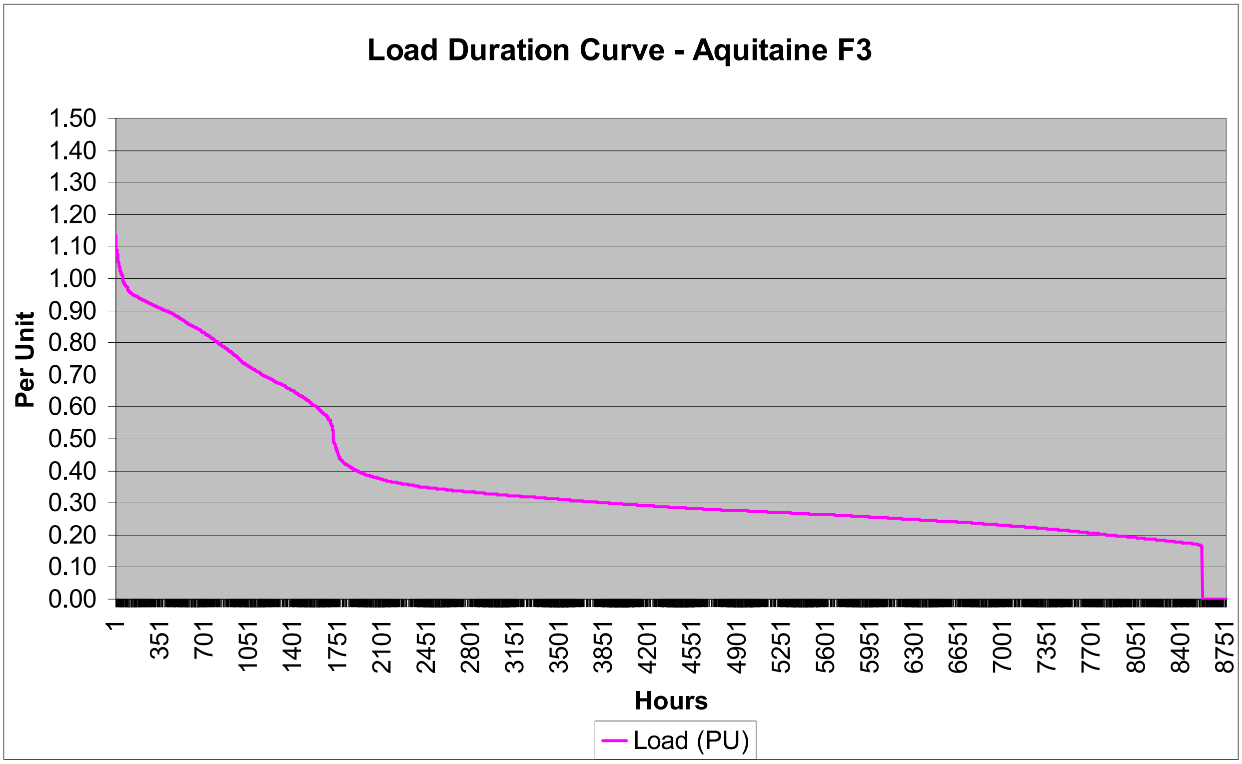

Load Duration Curve - Richview T5/T6
Per Unit
Hours
Load (PU)

44 kV System
13.8 kV Substations

Aquitaine MS







Load Duration Curve - Aquitaine F3
Per Unit
1.50
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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6301
6651
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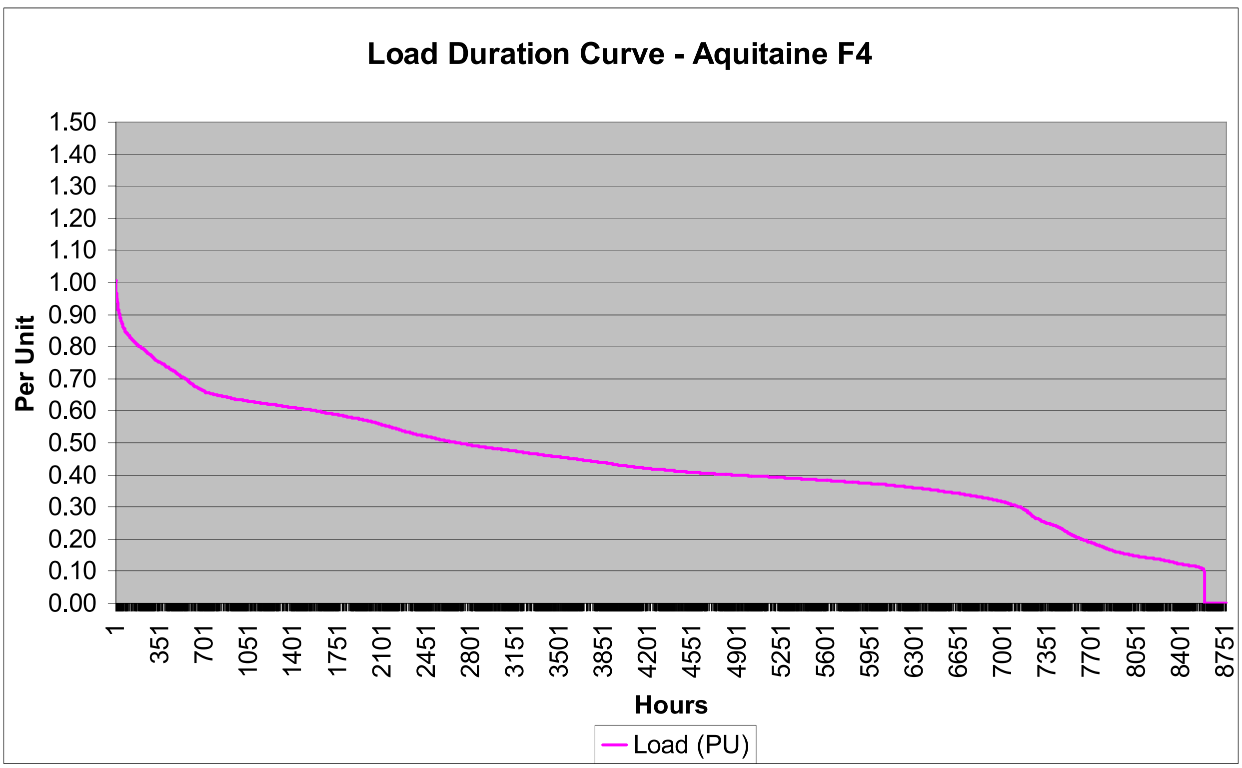
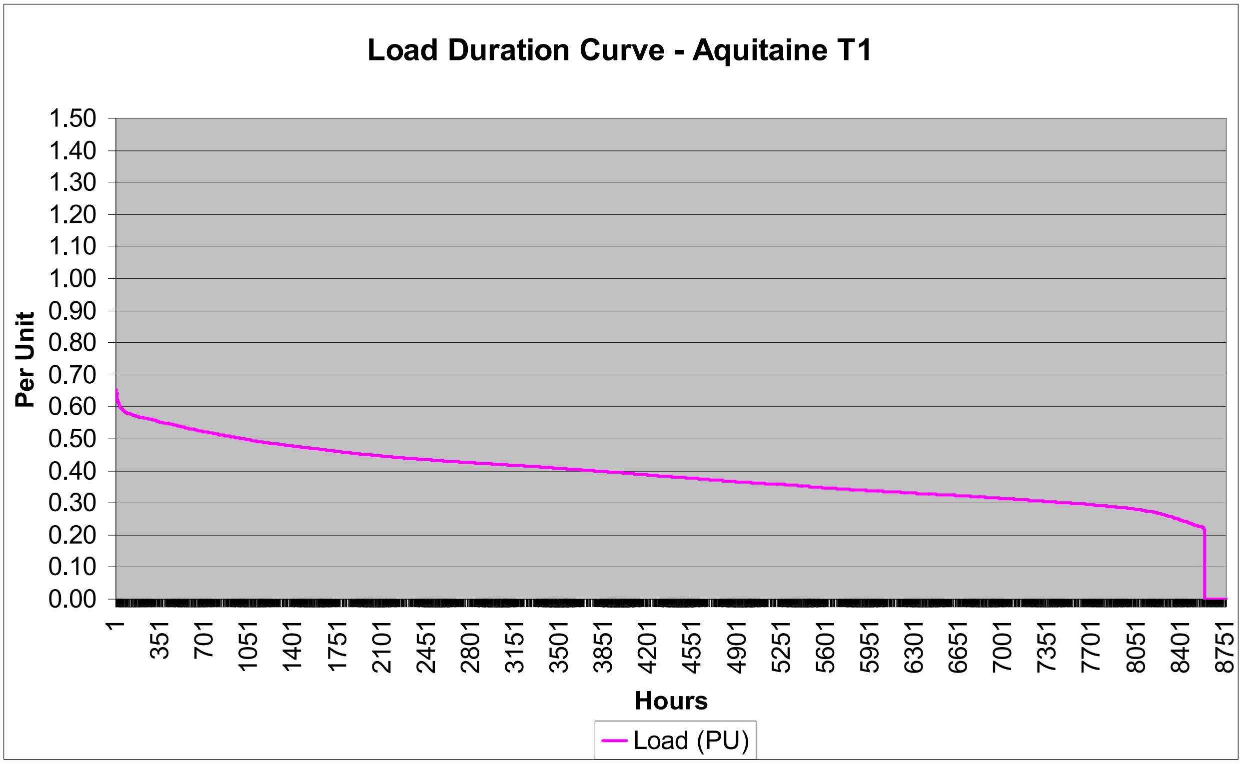
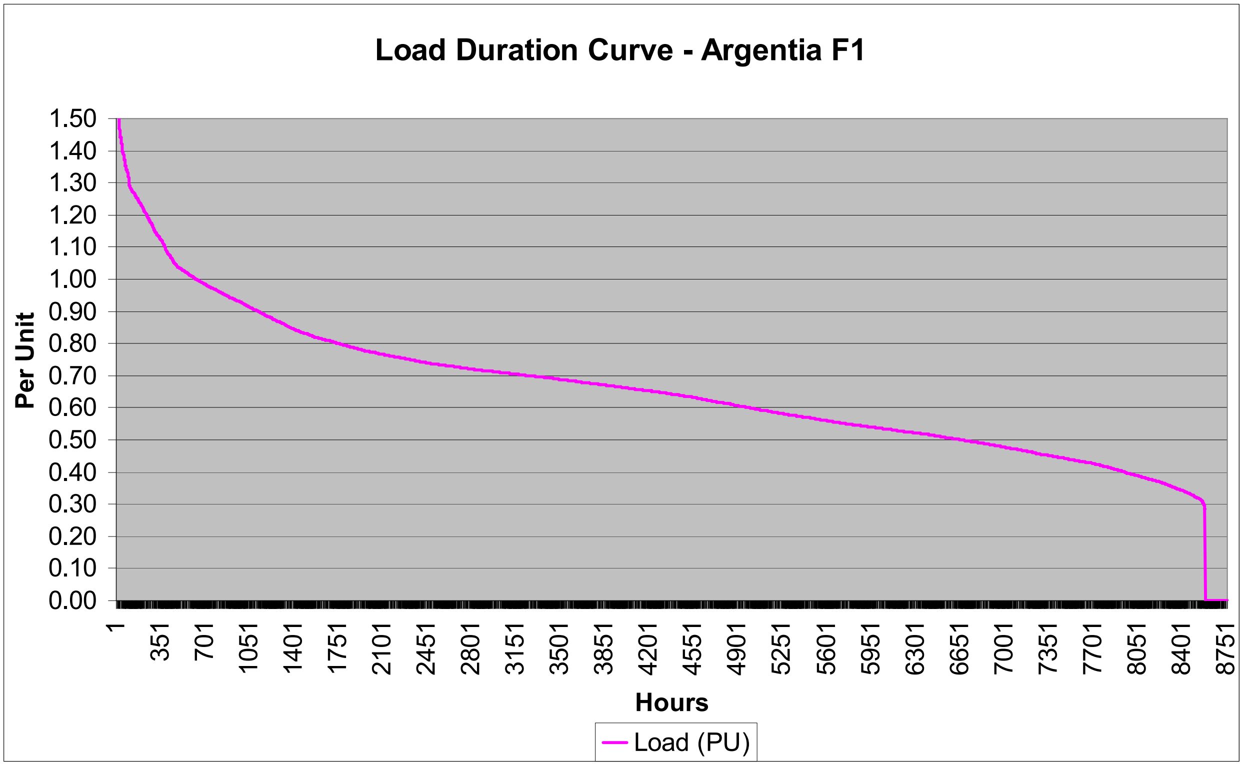
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Aquitaine F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Aquitaine T1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Argentia MS


Load Duration Curve - Argentia F1
Per Unit
1.50
1.40
1.30
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6651
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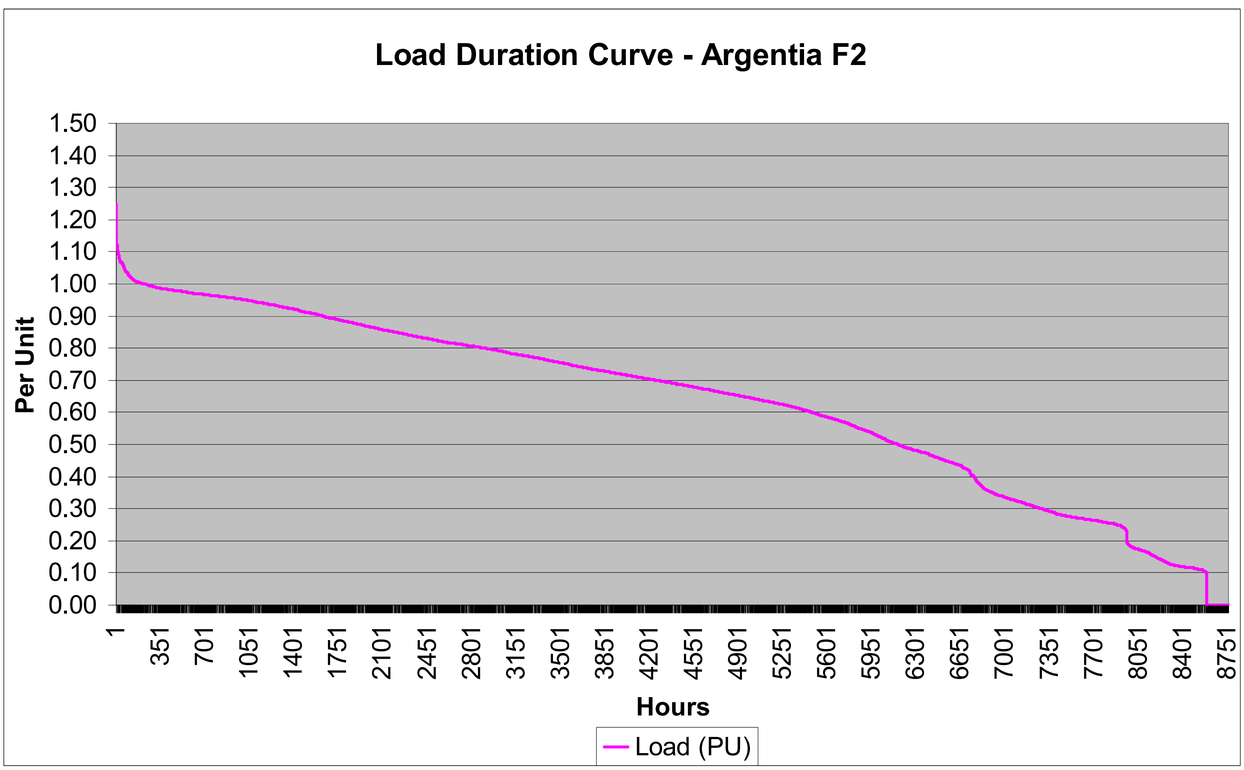
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Argentia F2
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6651
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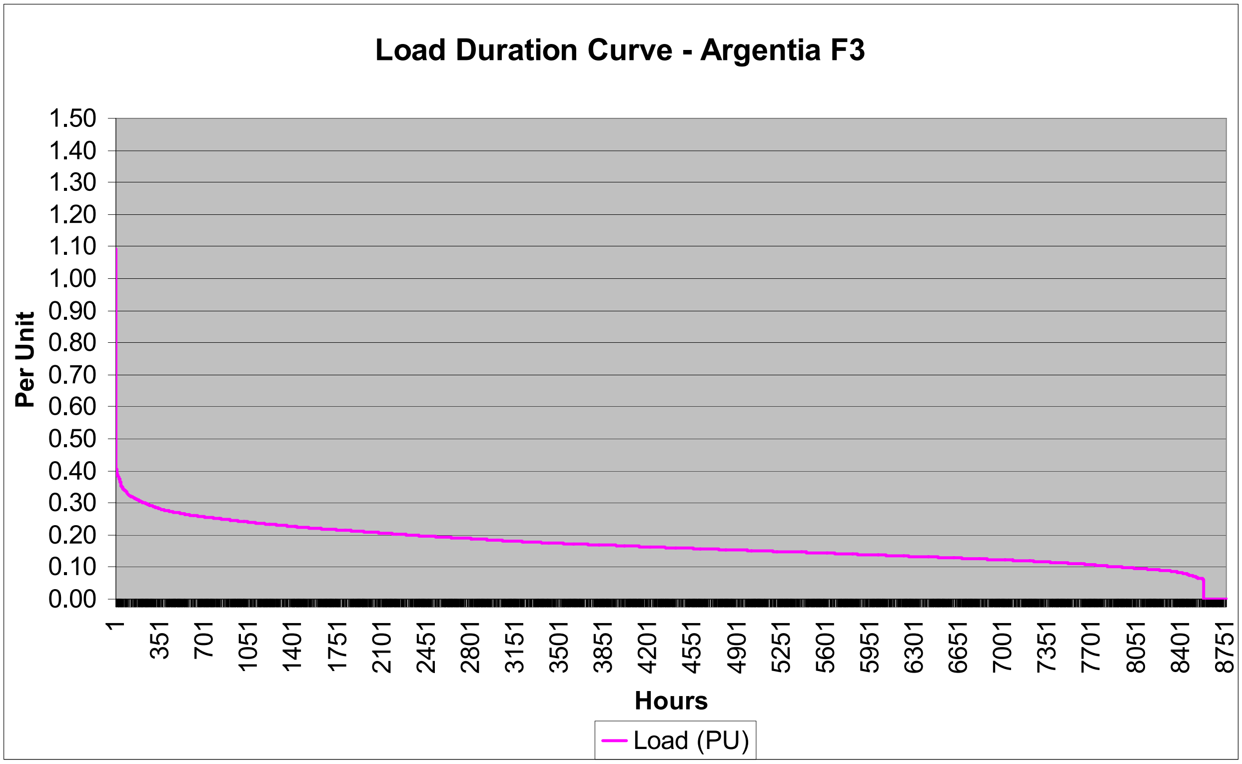
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Argentia F3
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5601
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6301
6651
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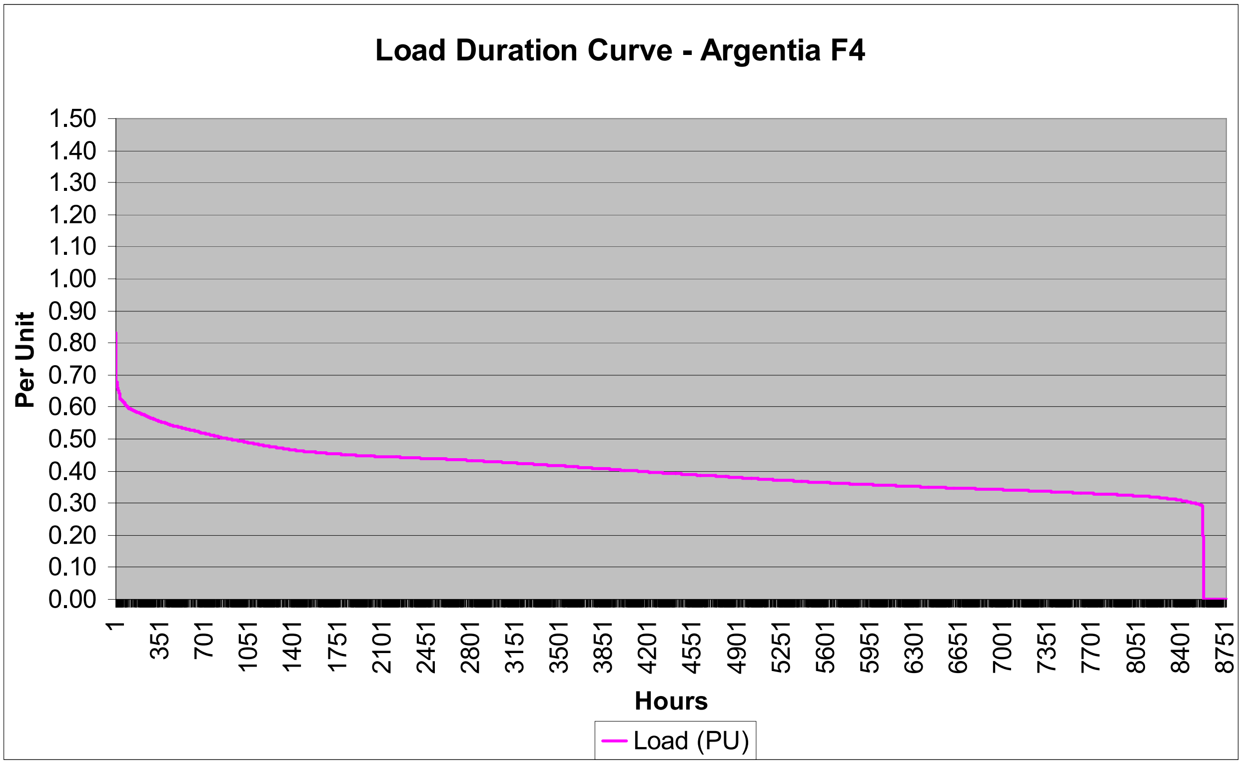
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Argentia F4
Per Unit
1.50
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1.30
1.20
1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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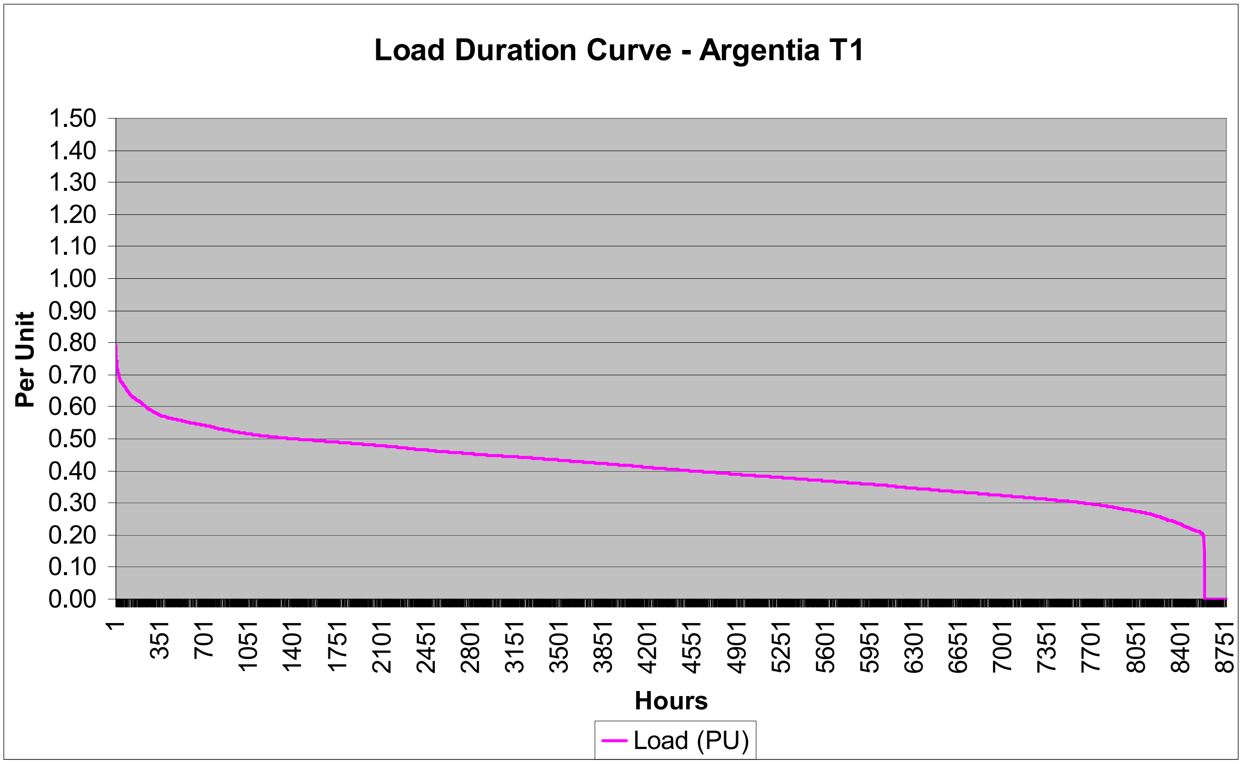
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Argentia T1
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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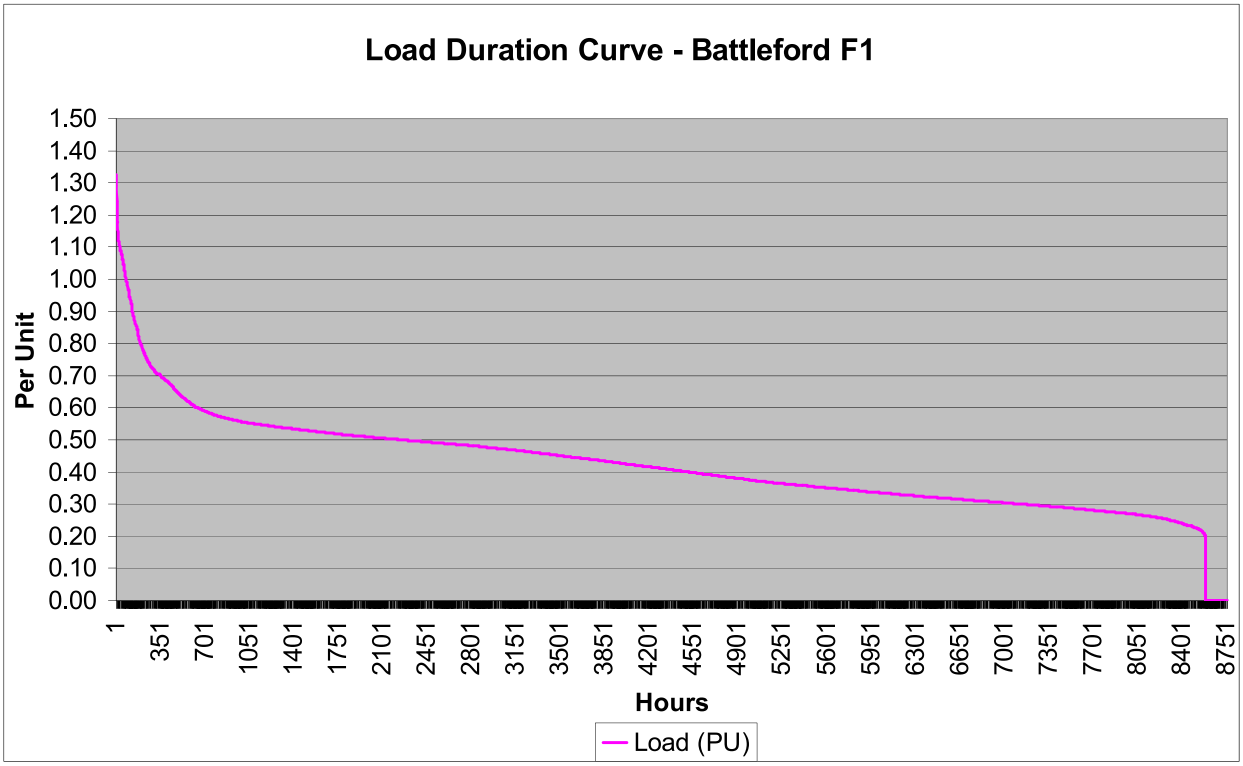
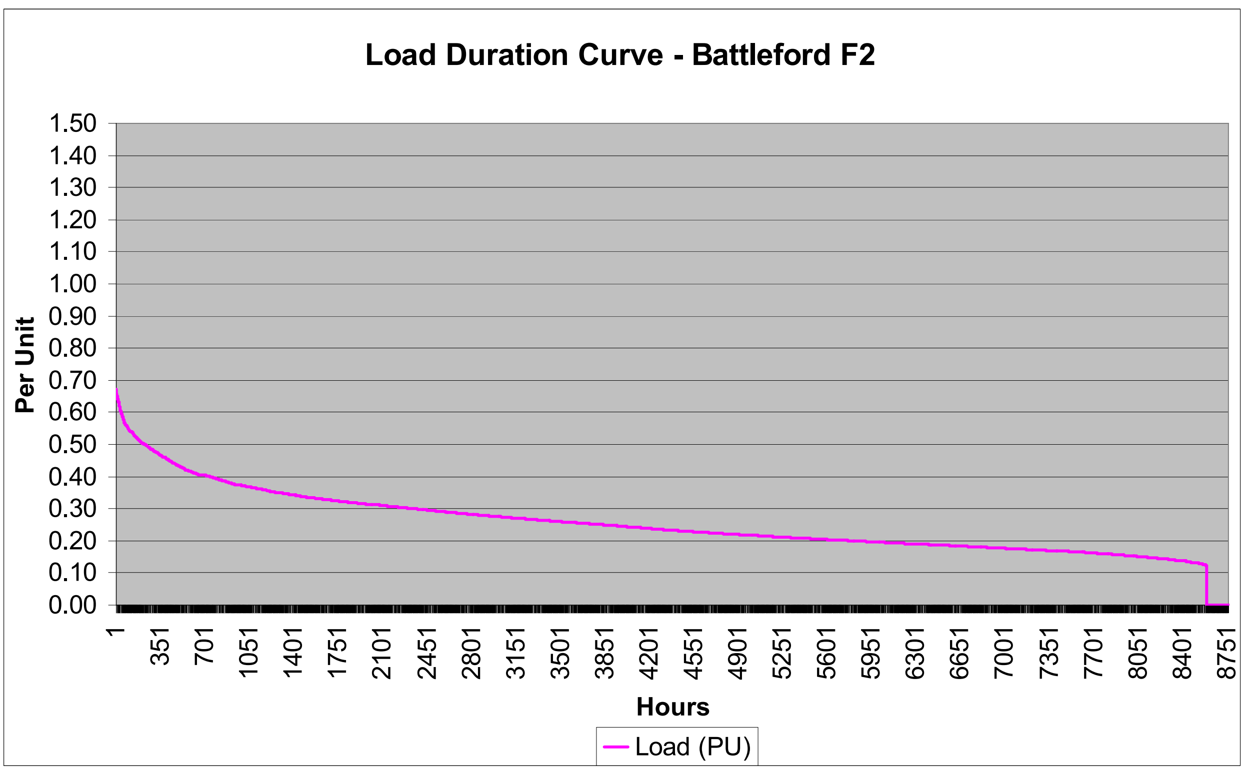
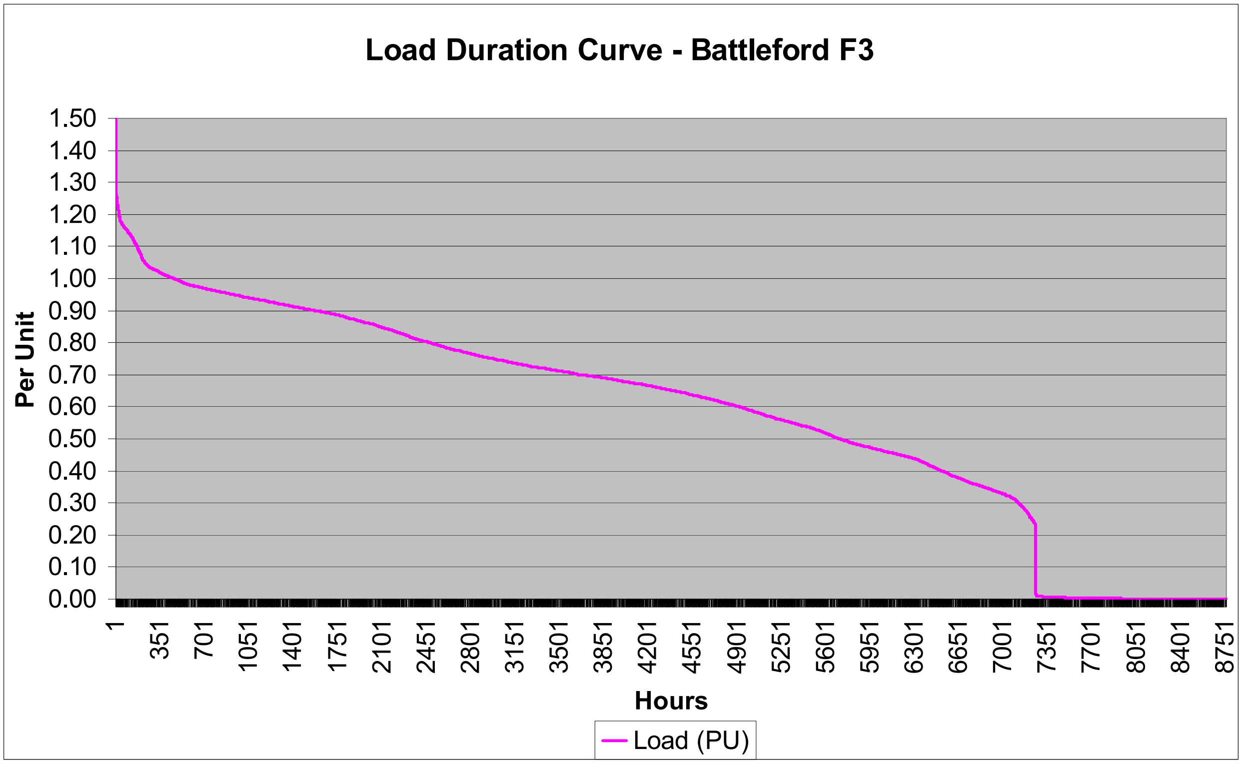
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Battleford MS






Load Duration Curve - Battleford F3
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1.40
1.30
1.20
1.10
1.00
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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4901
5251
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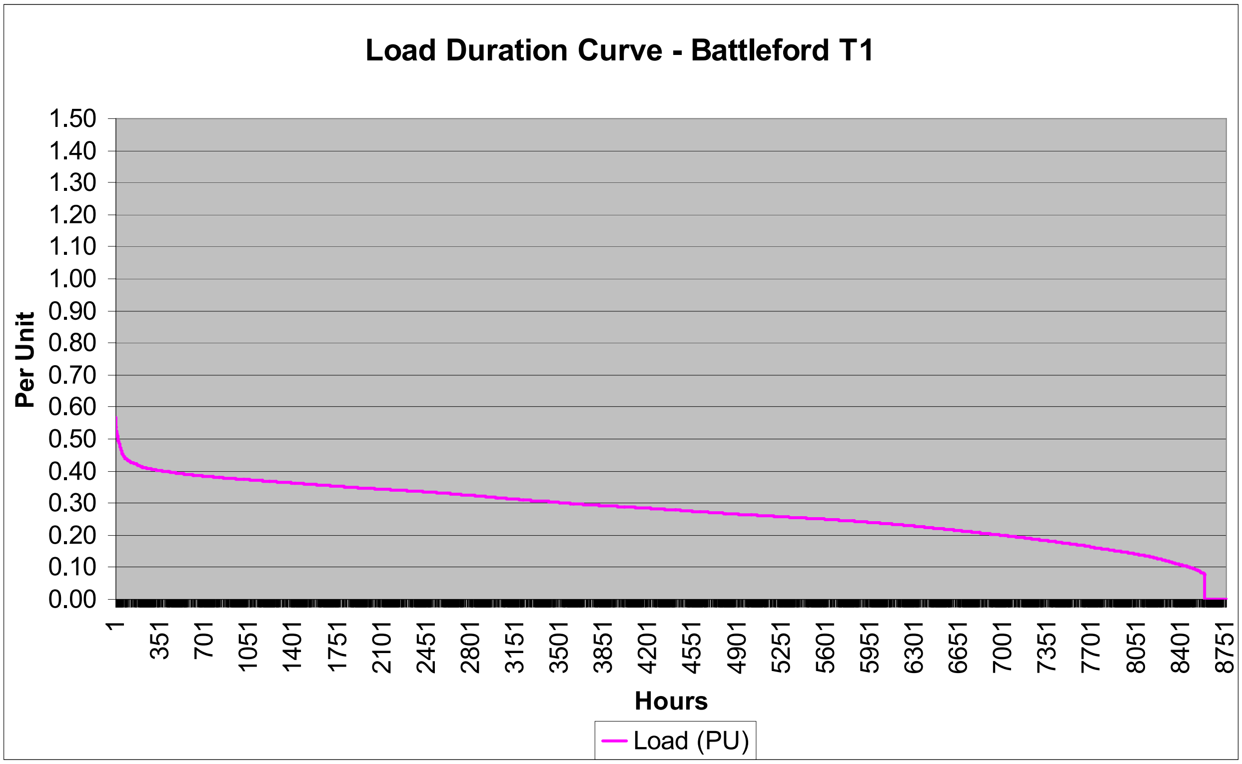
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Battleford T1
1.50
1.40
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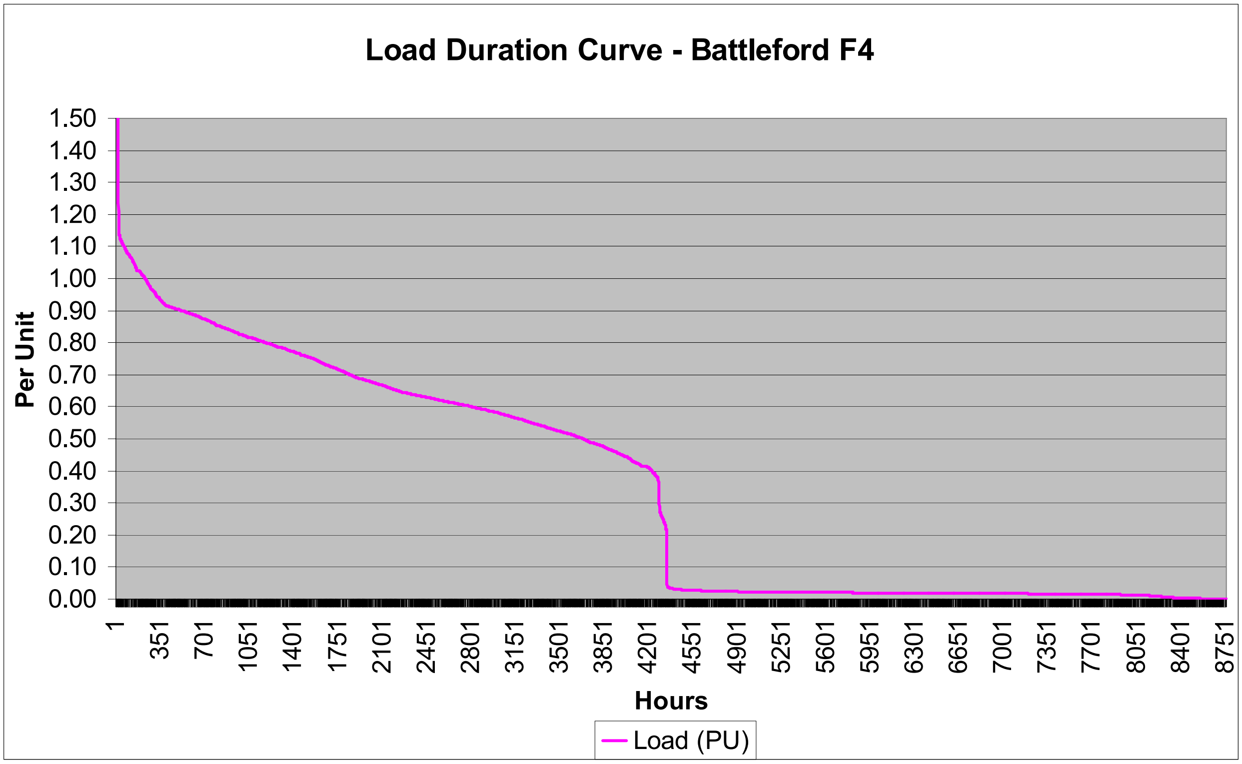
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Battleford F4
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1.00
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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6651
7001
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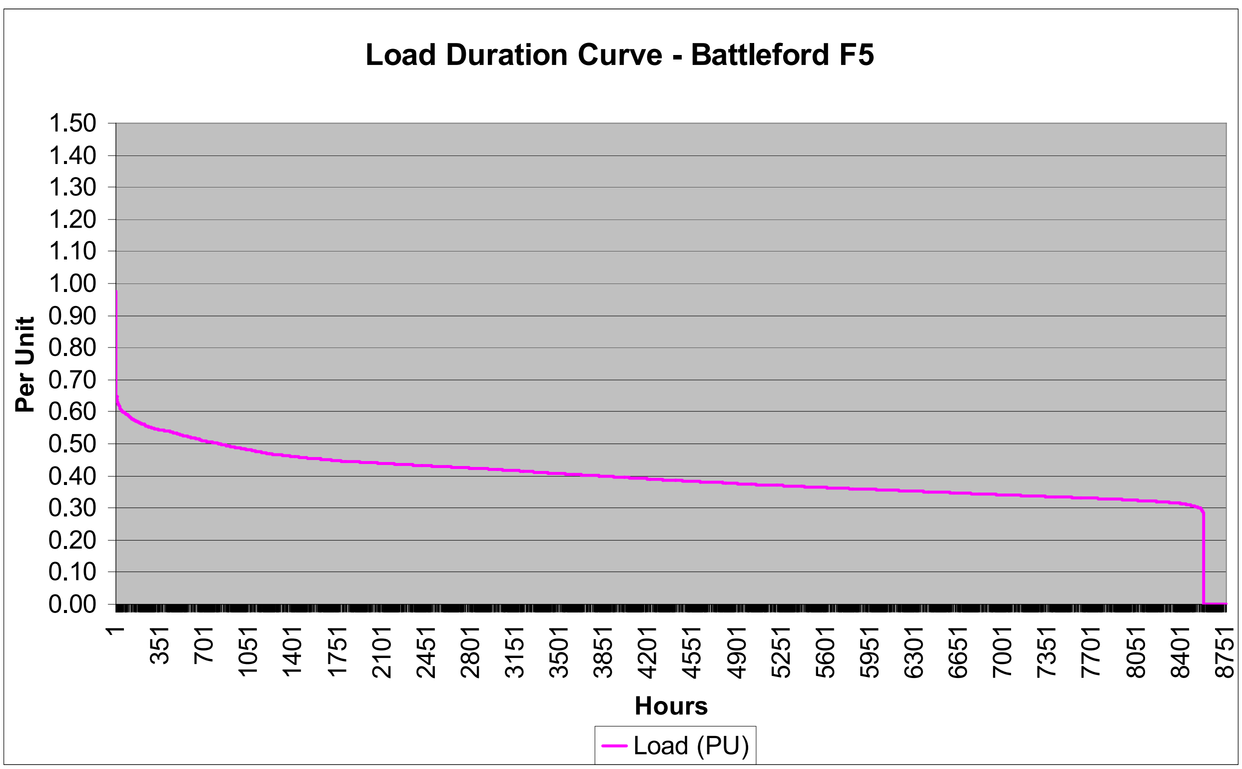
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Battleford F5
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1.40
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1.20
1.10
1.00
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0.80
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
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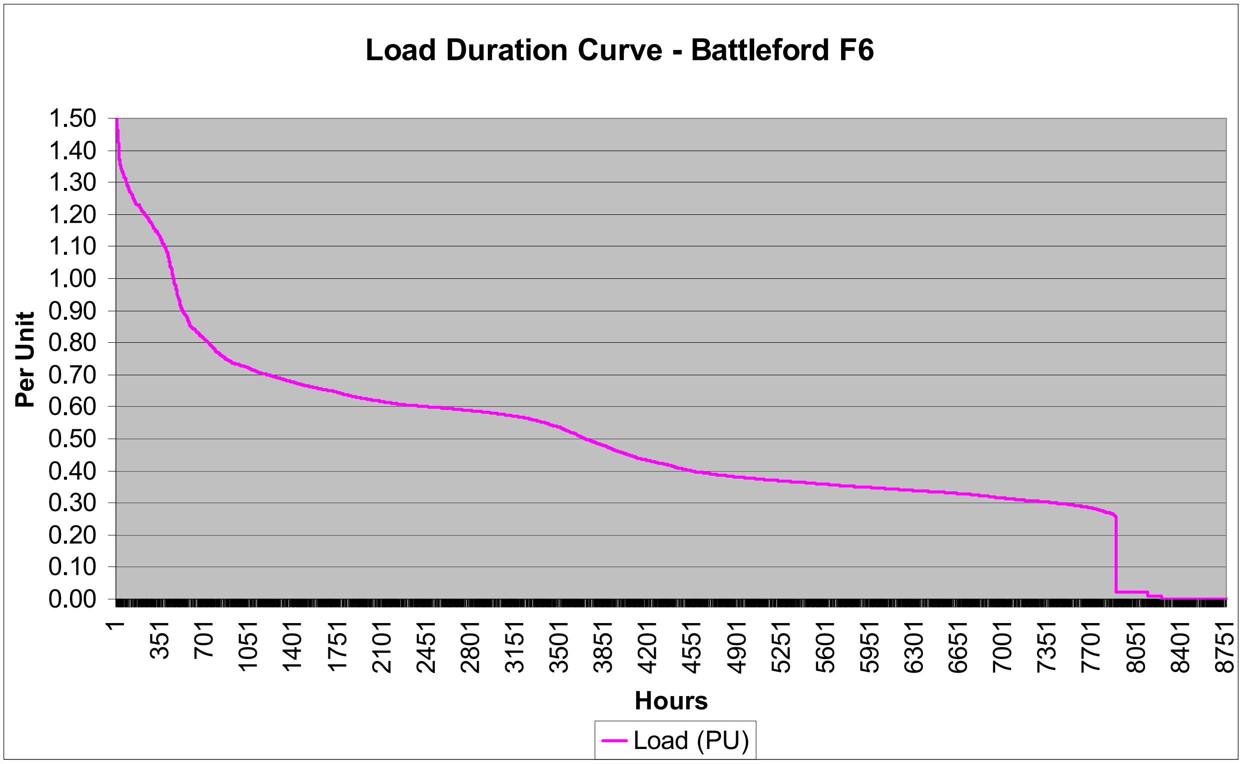
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Battleford F6
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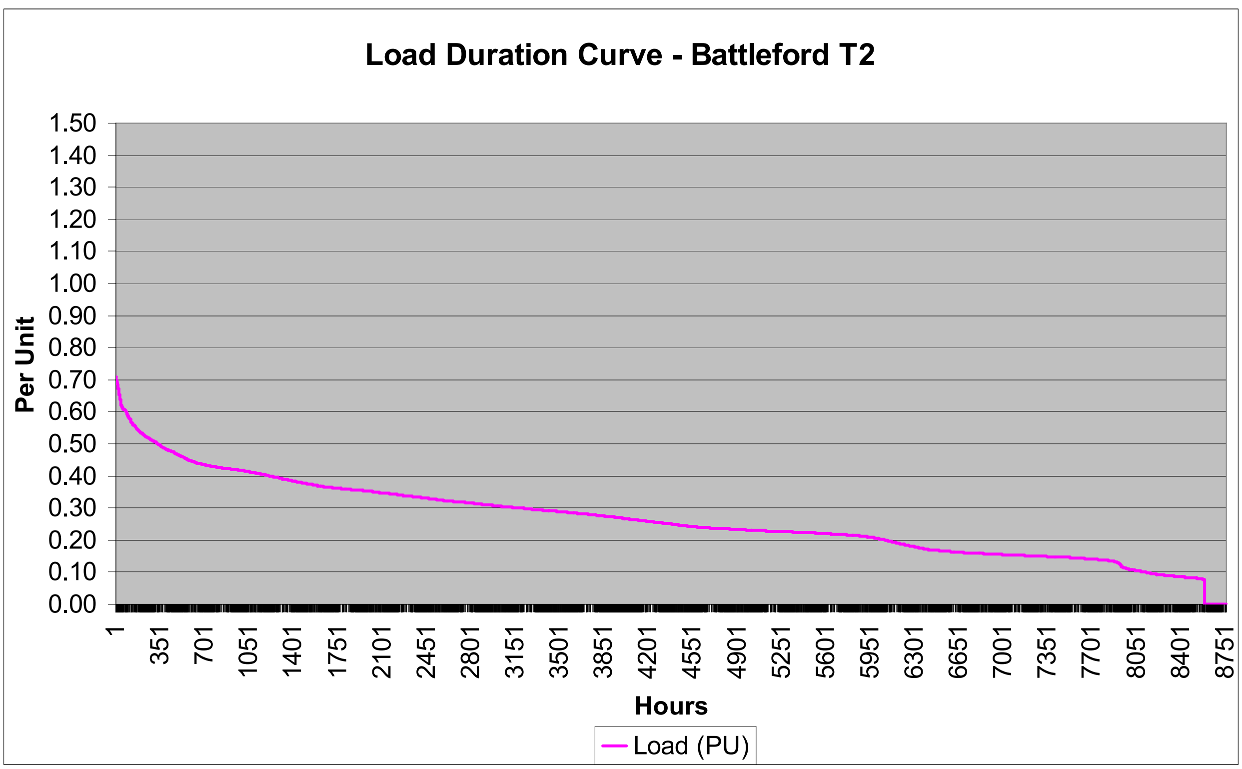
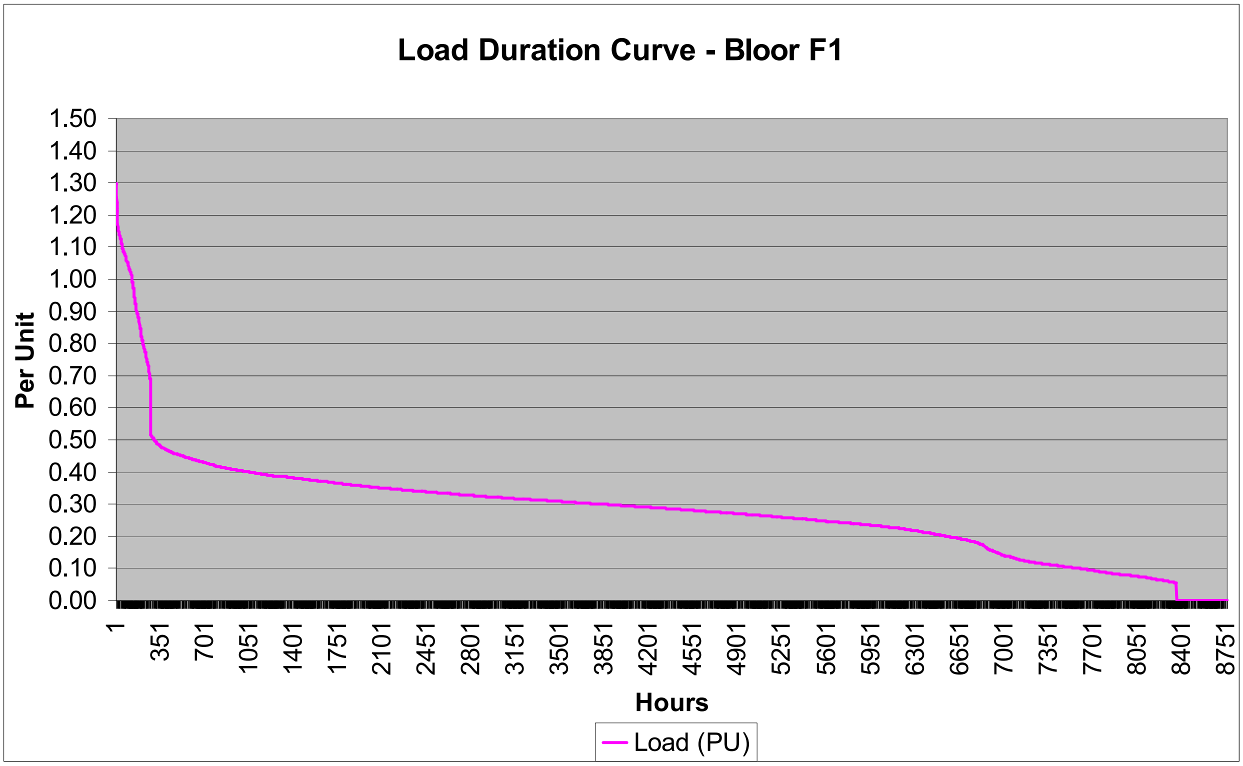
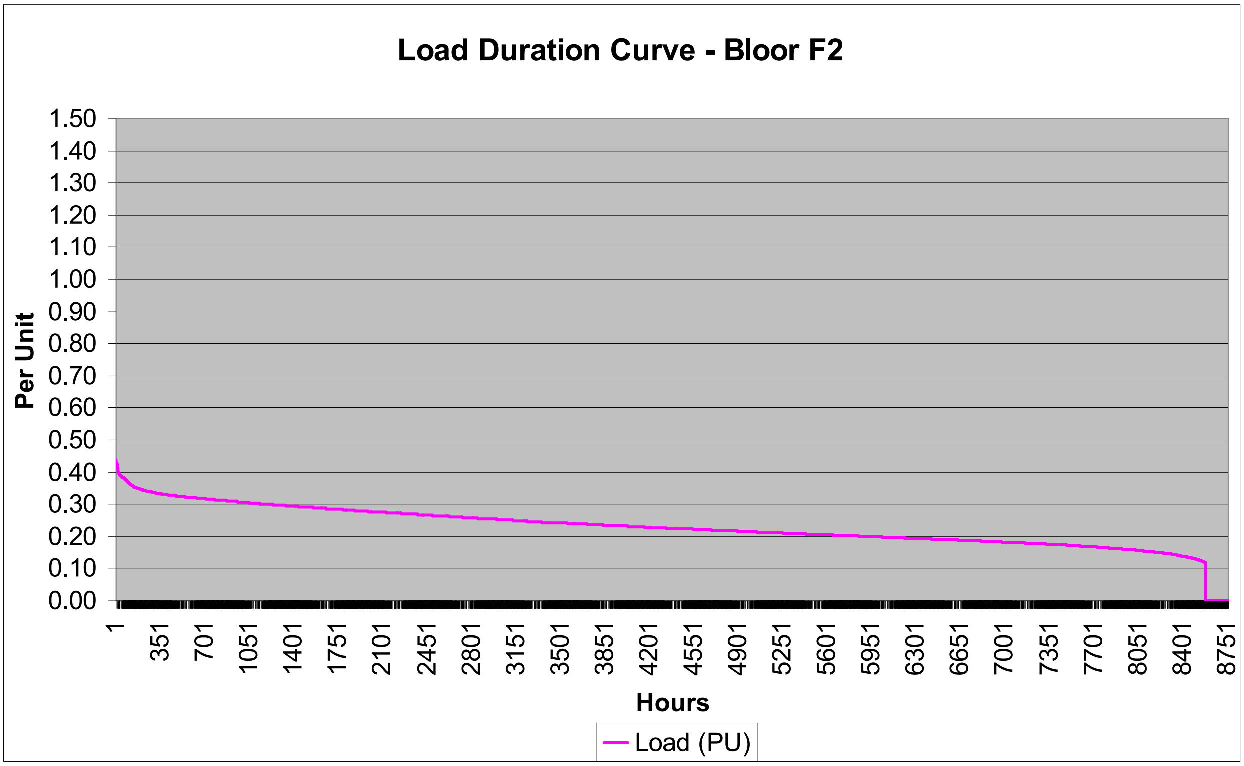
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Battleford T2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Bloor MS



Load Duration Curve - Bloor F1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Bloor F2
1.50
1.40
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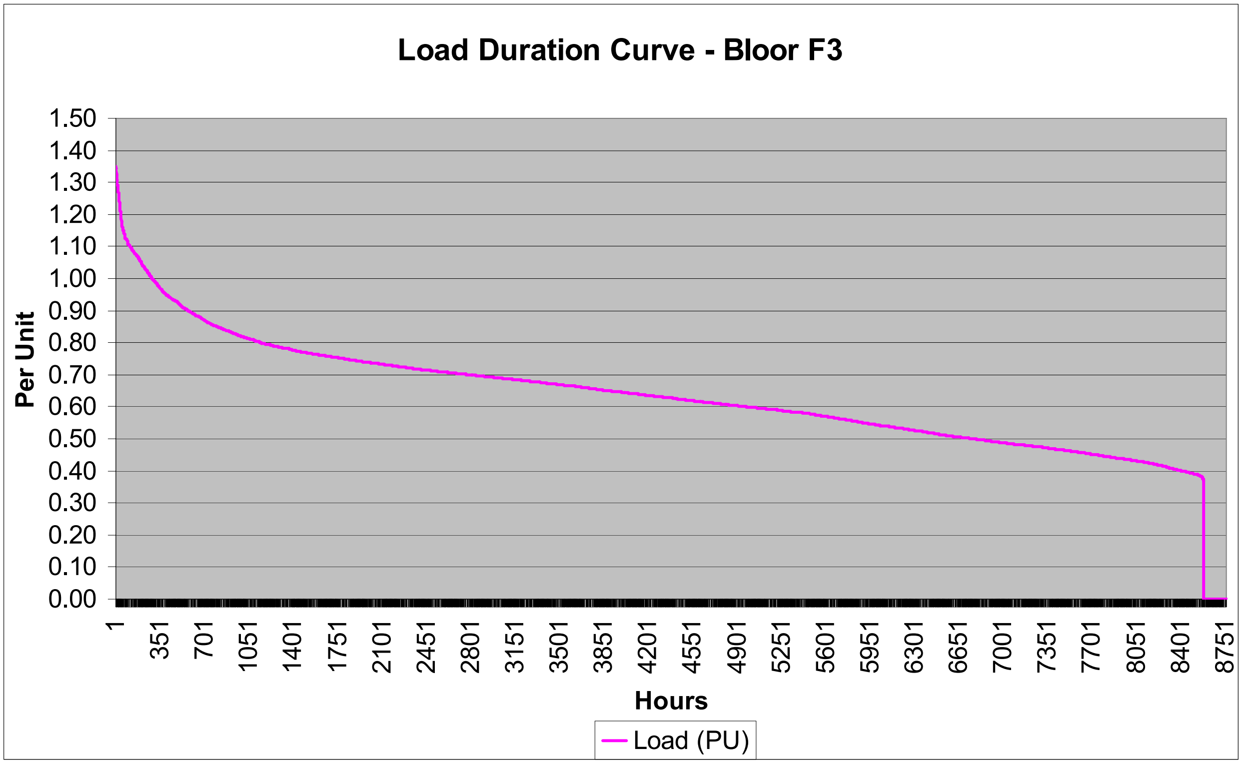
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bloor F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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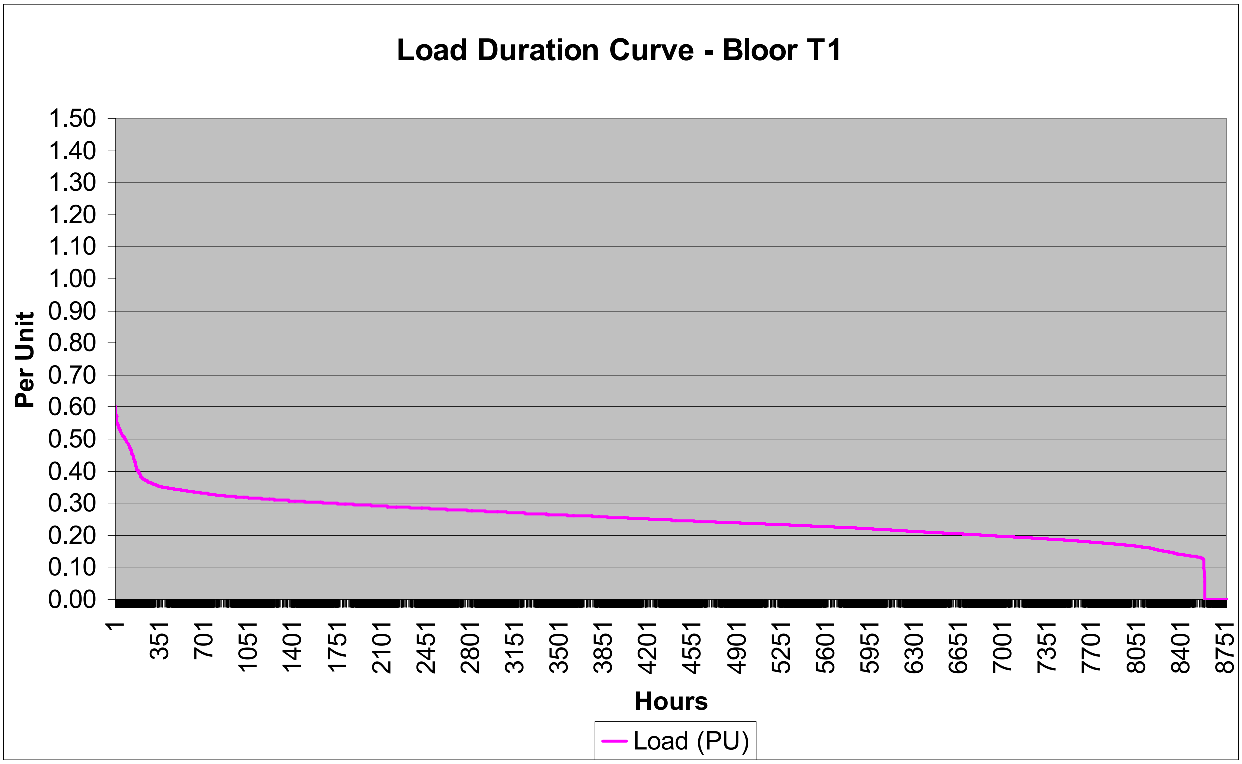
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bloor T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5601
5951
6301
6651
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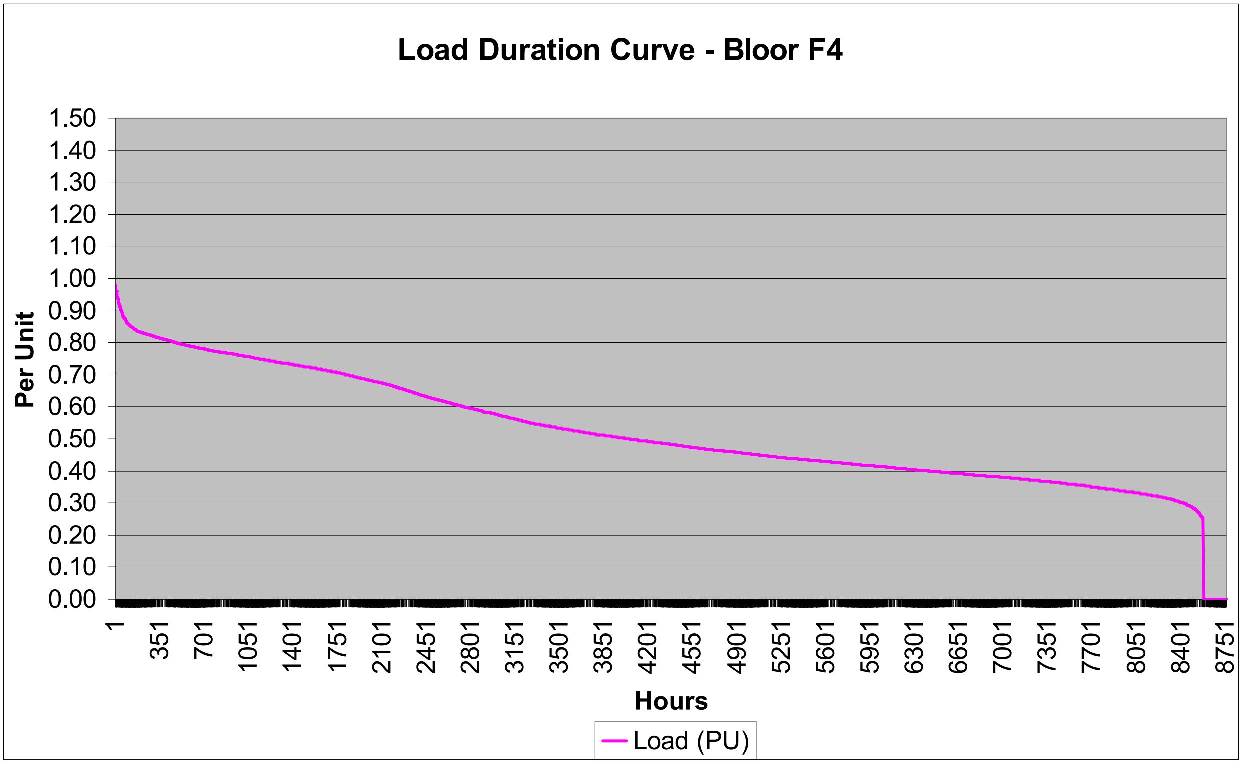
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bloor F4
Per Unit
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1.30
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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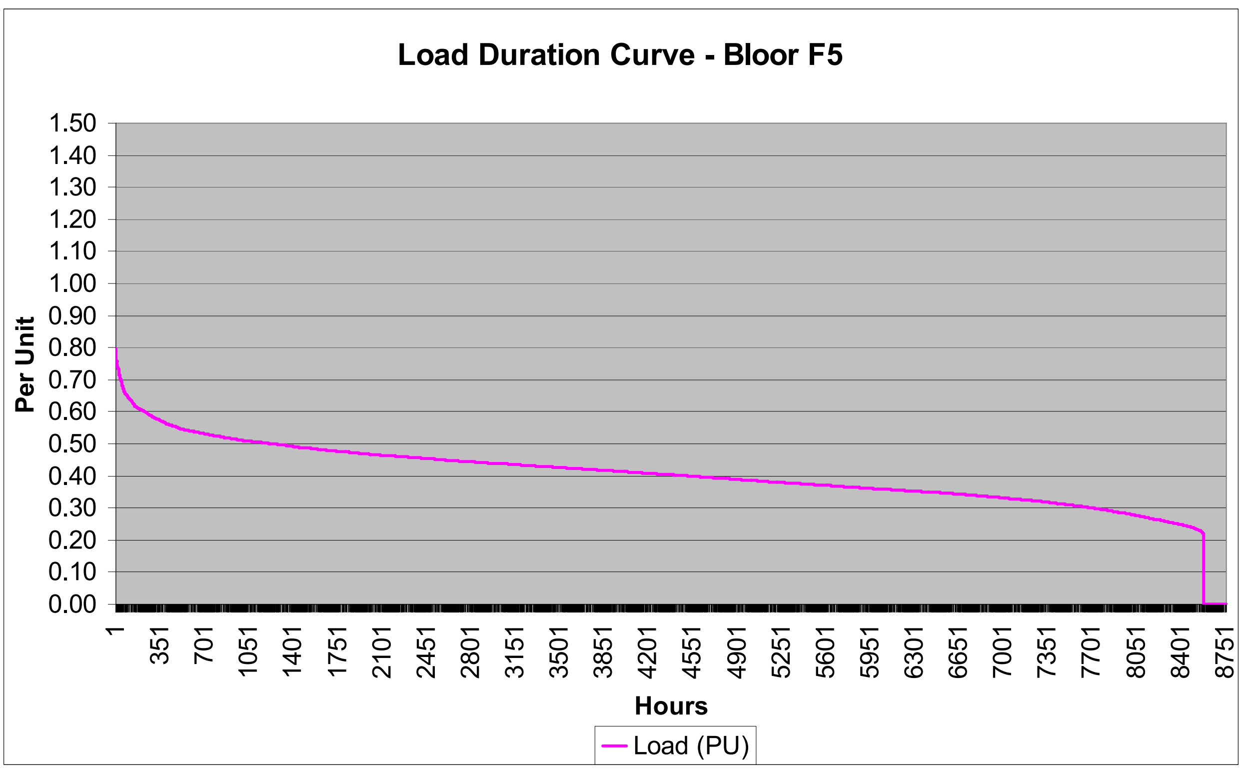
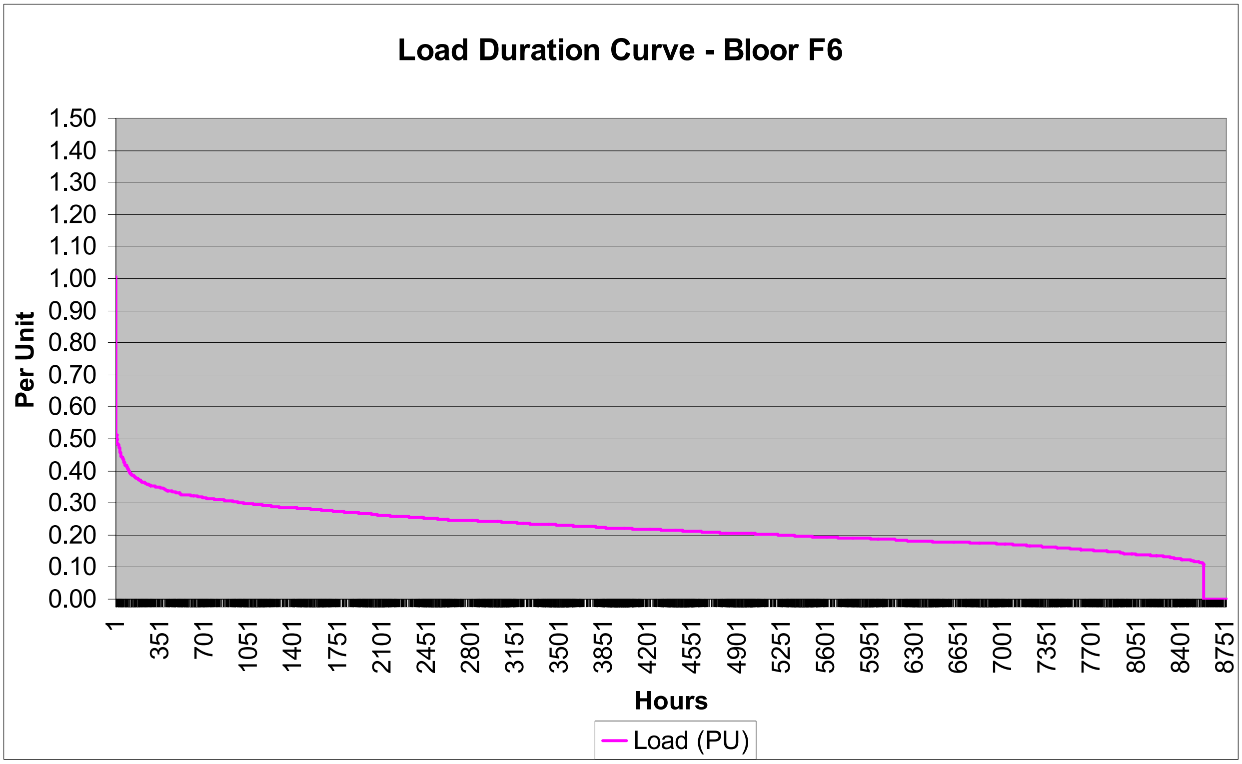
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bloor F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bloor F6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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4901
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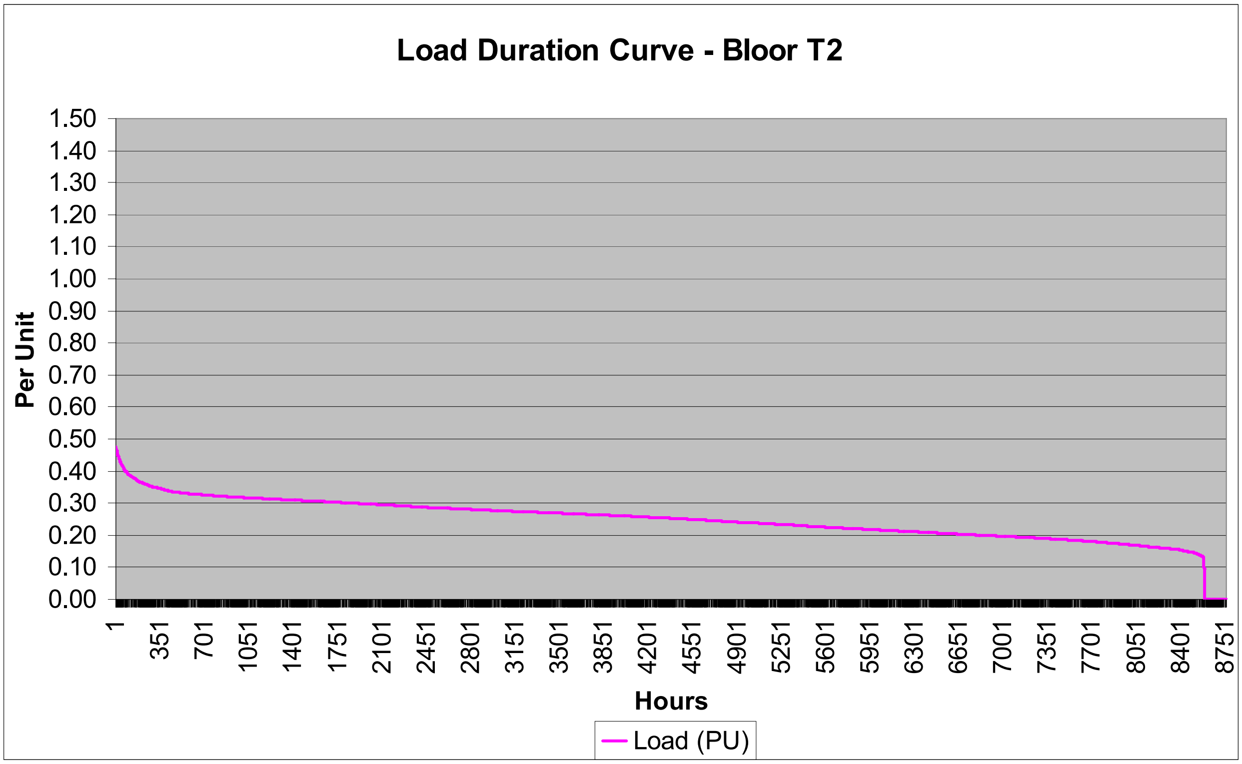
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bloor T2
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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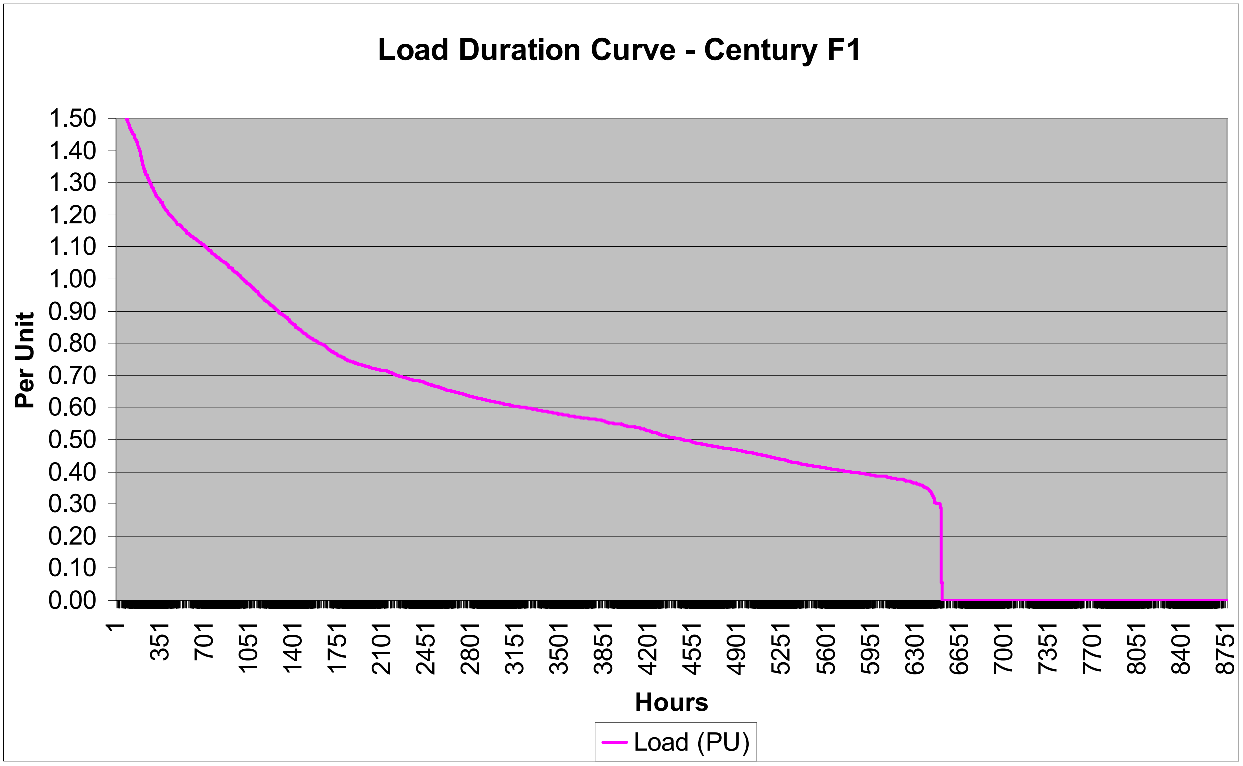
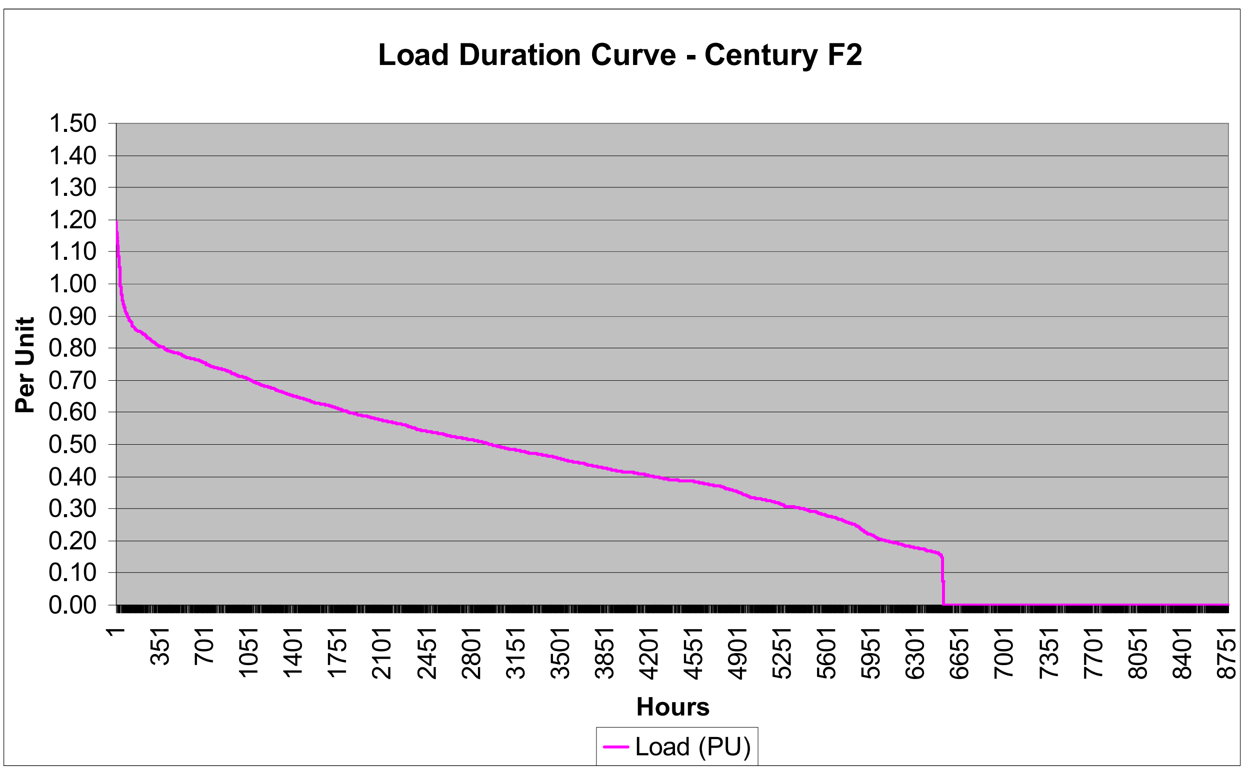
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Century MS



Load Duration Curve - Century F1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Century F2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
5601
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6301
6651
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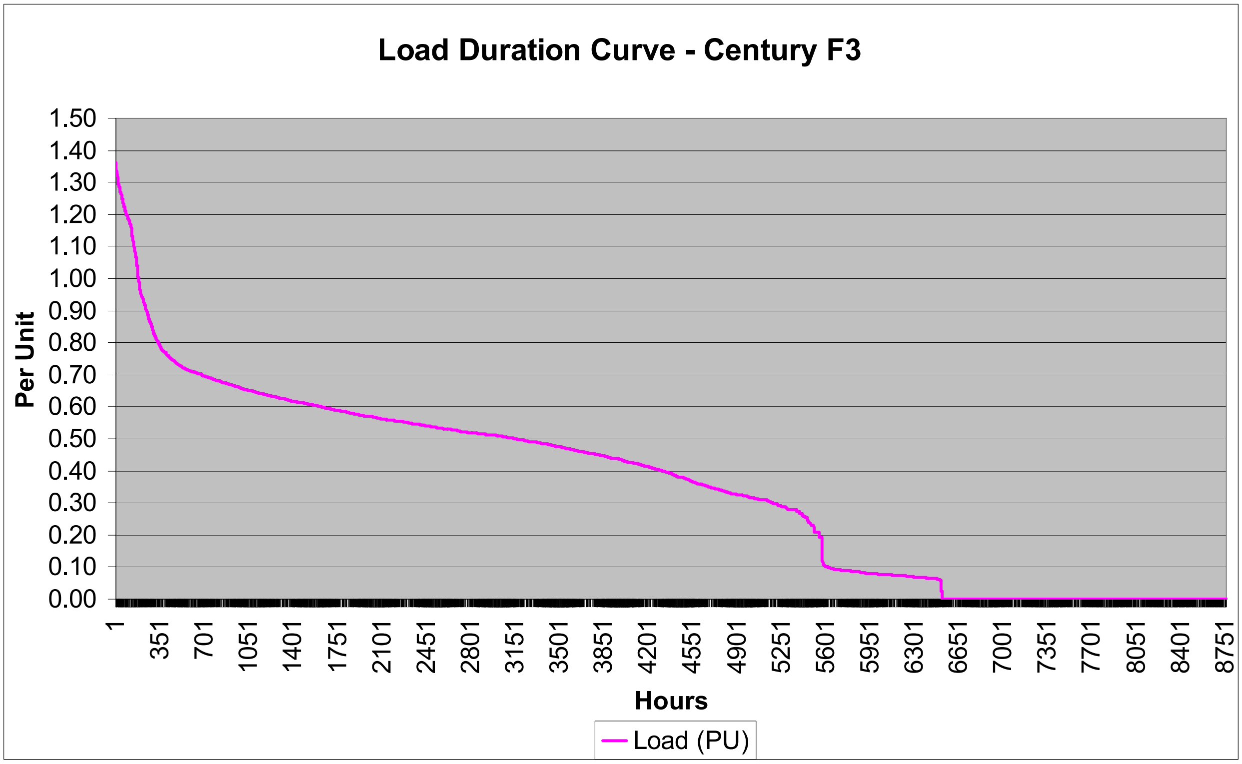
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Century F3
Per Unit
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1.30
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
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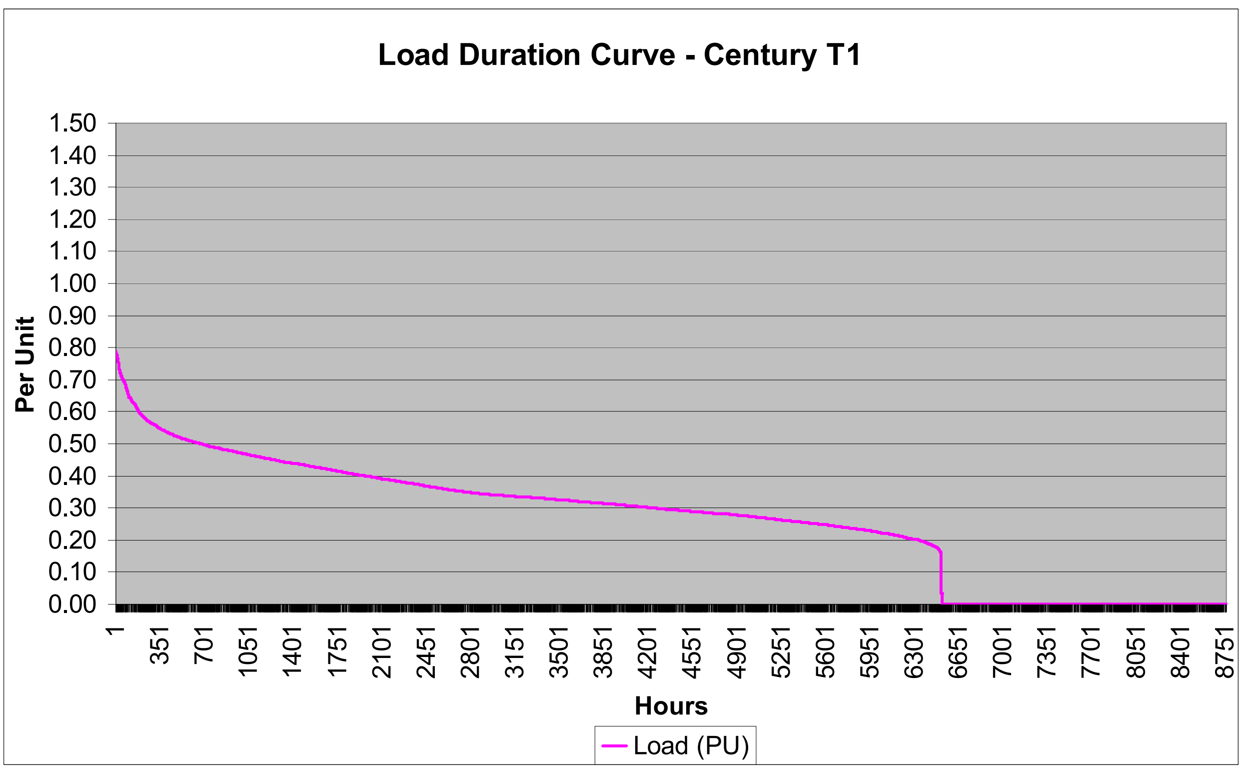
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Century T1
Per Unit
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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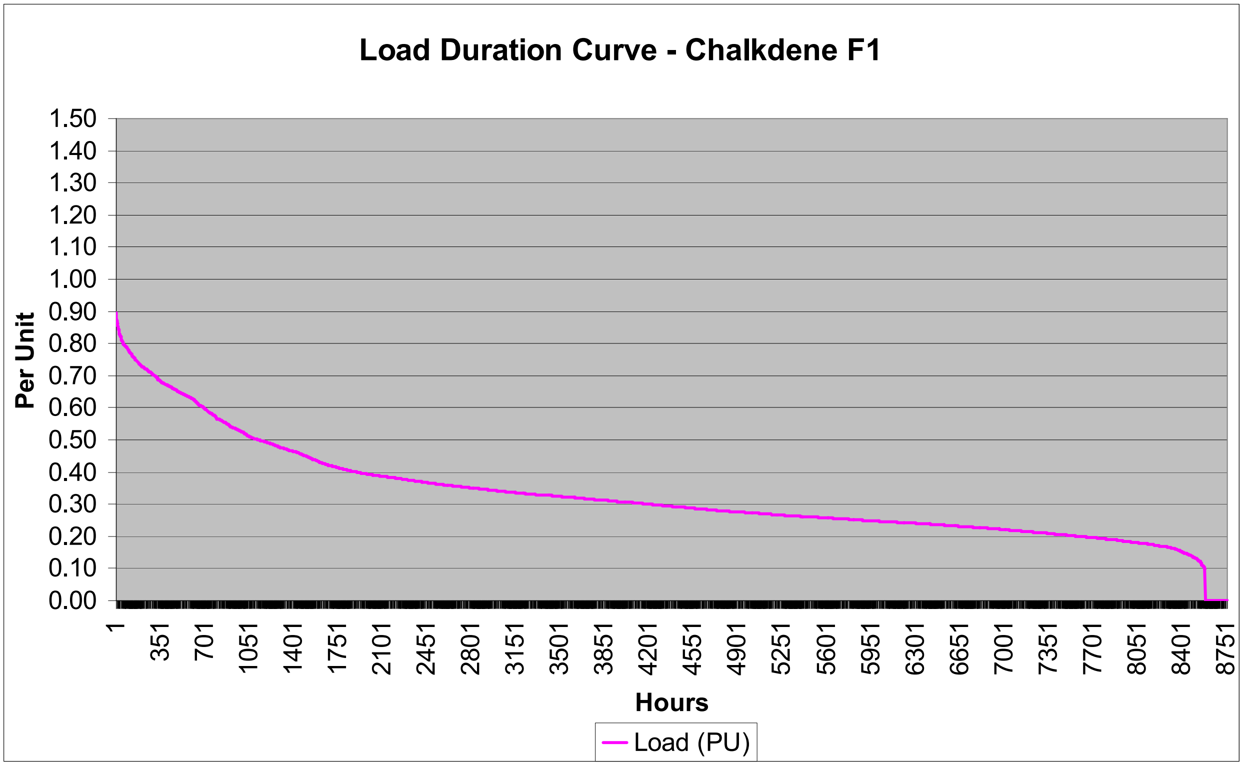
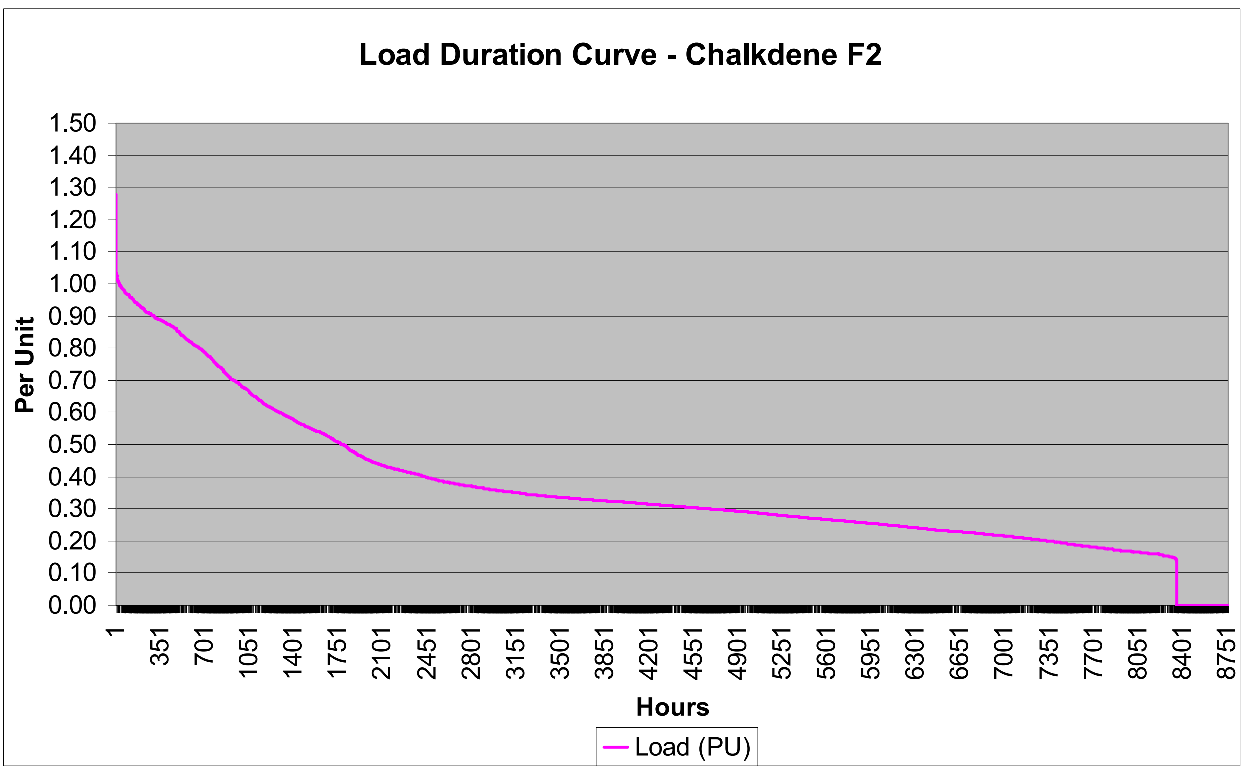
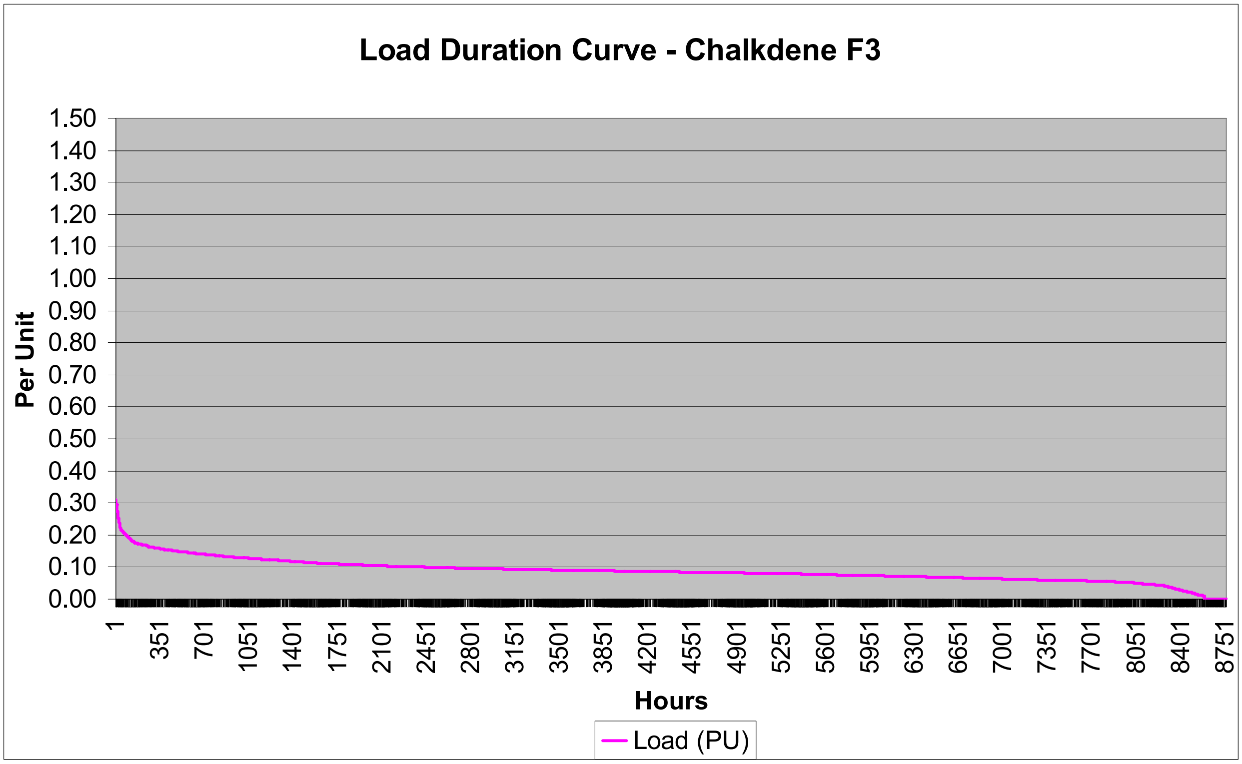
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Chalkdene MS






Load Duration Curve - Chalkdene F3
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6651
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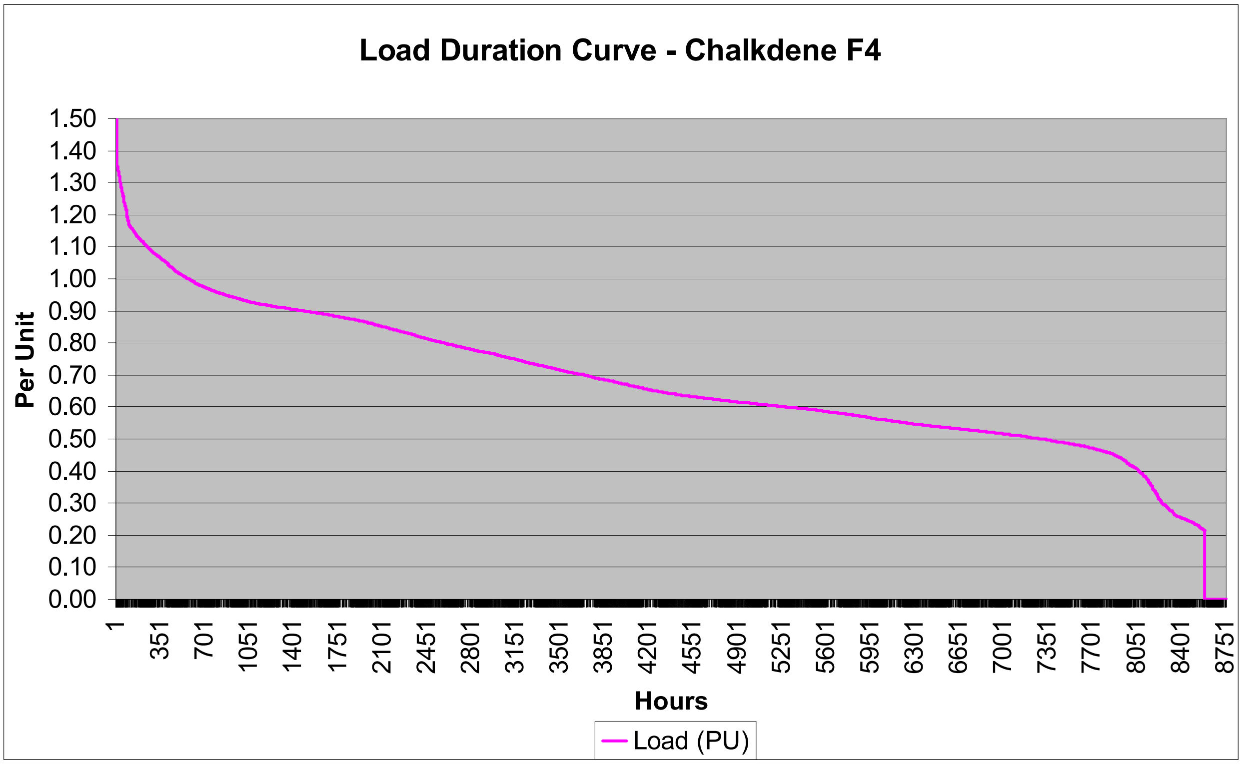
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Chalkdene F4
Per Unit
1.50
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6301
6651
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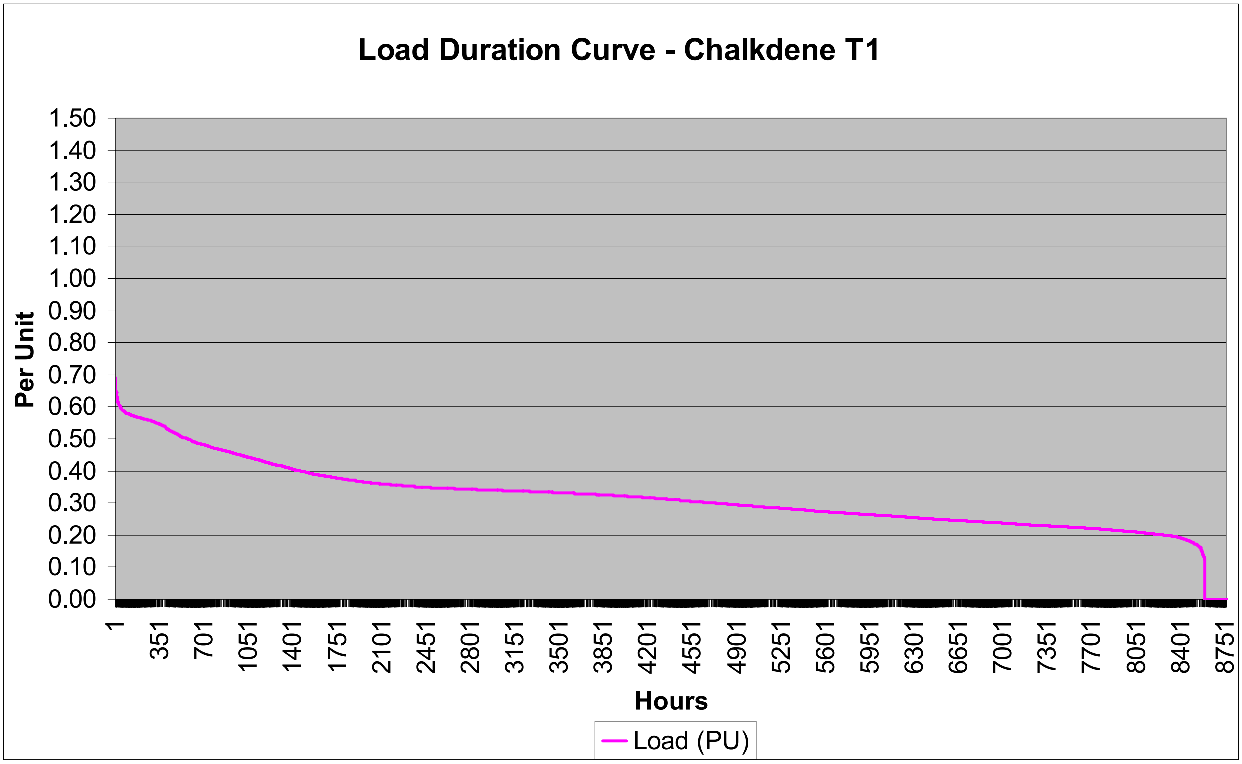
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Chalkdene T1
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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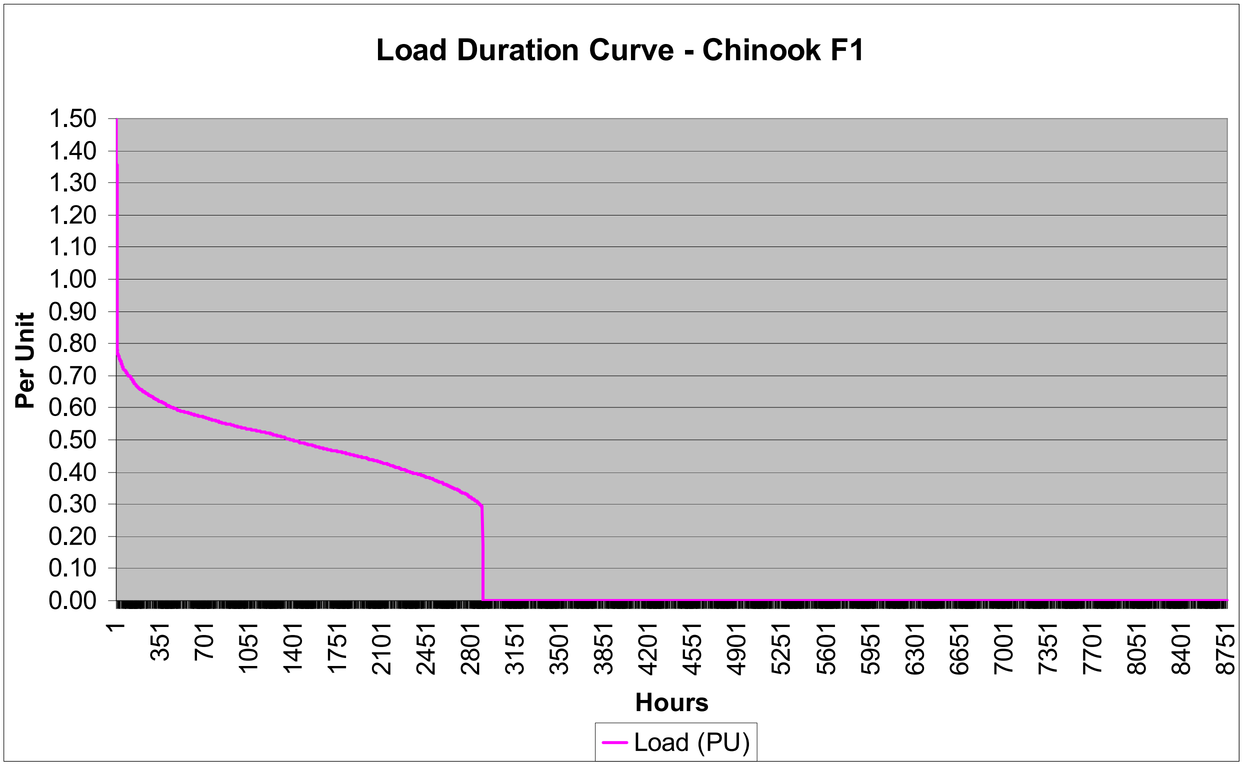
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Chinook MS



Load Duration Curve - Chinook F1
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3851
4201
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6301
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8051
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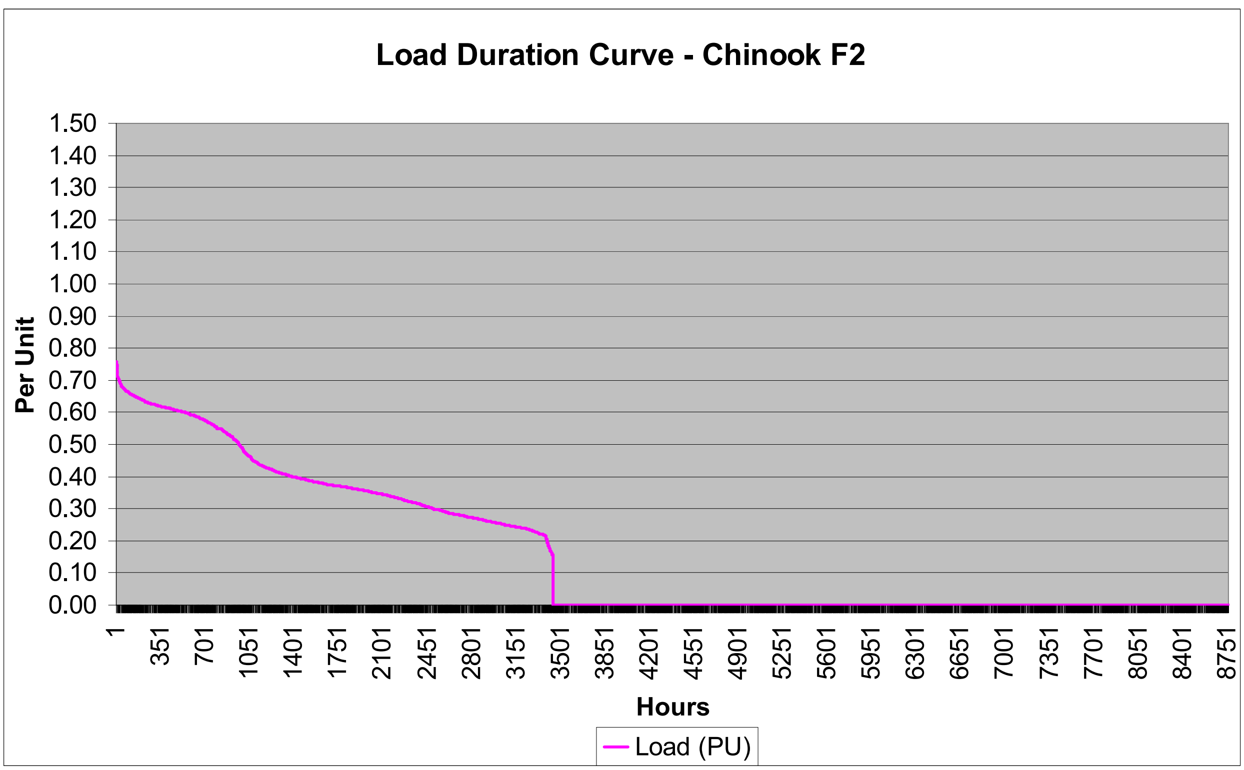
8751
Hours
Load (PU)



Load Duration Curve - Chinook F2
Per Unit
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1.30
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
3501
3851
4201
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6651
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8051
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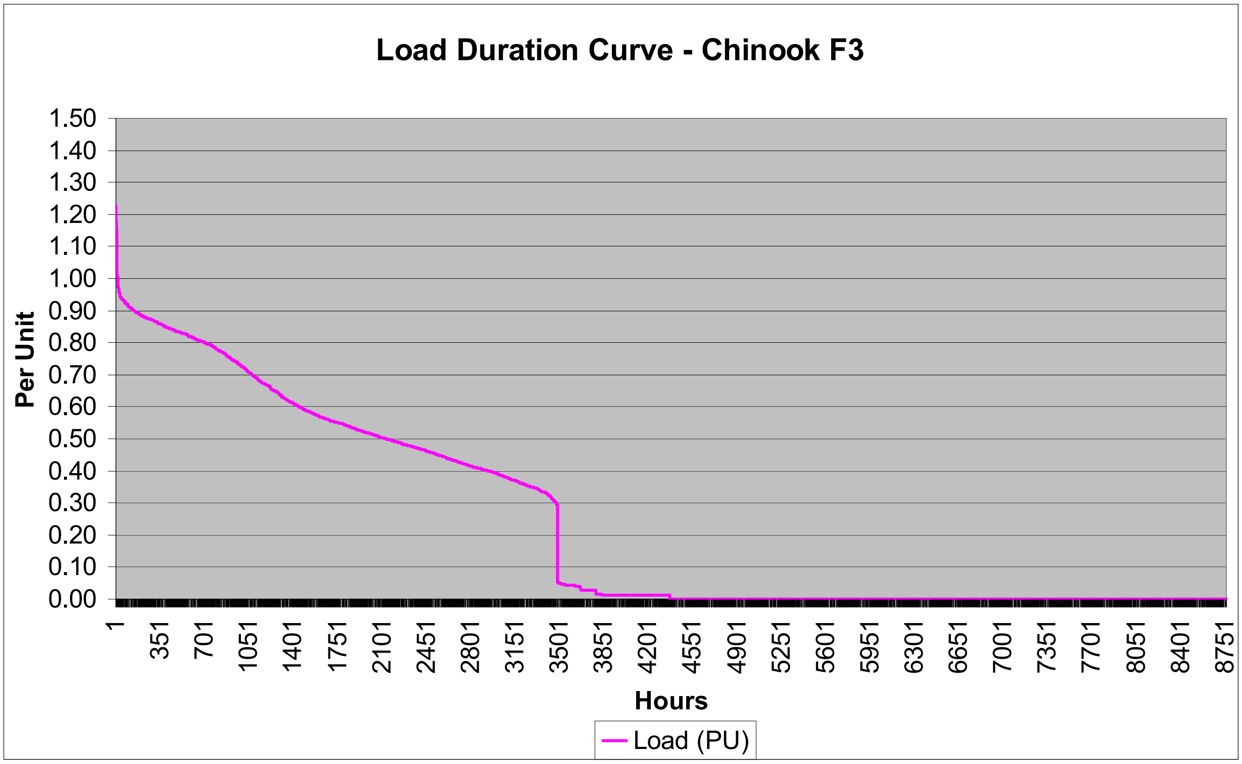
8751
Hours
Load (PU)


Load Duration Curve - Chinook F3
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
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3851
4201
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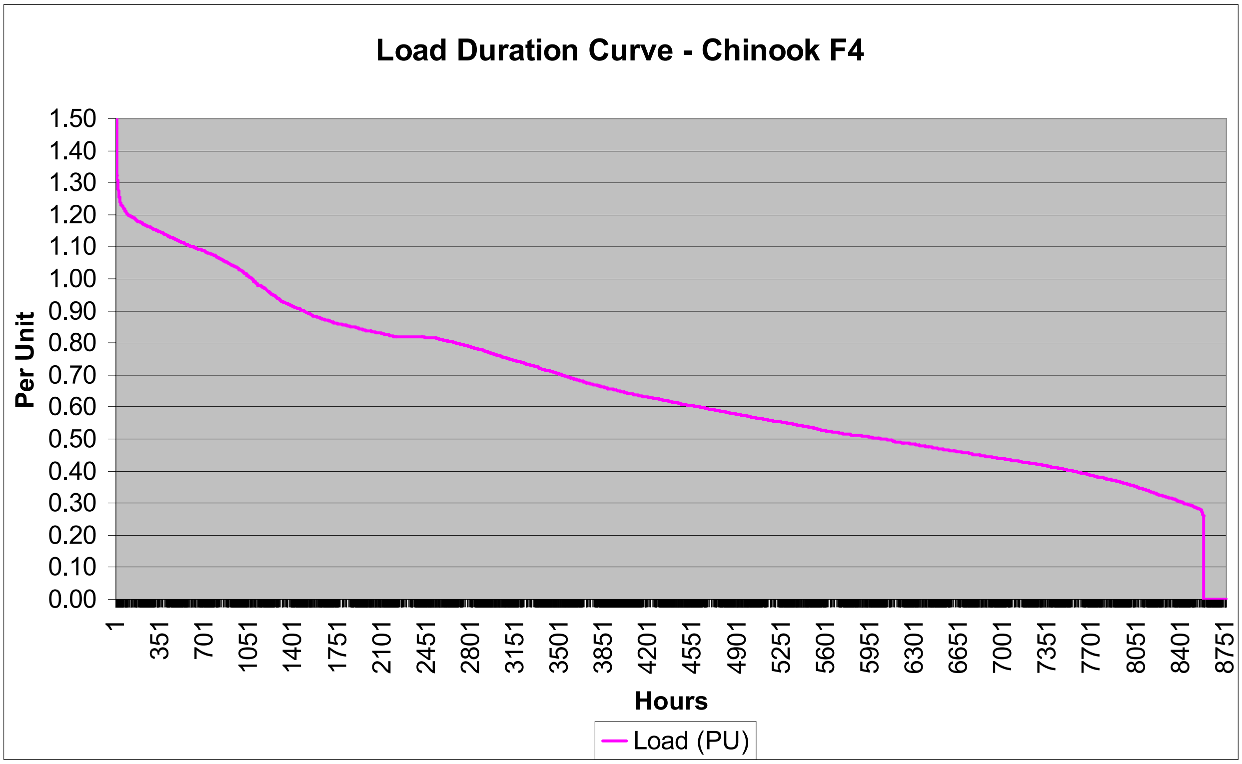
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Chinook F4
Per Unit
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1.10
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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2451
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3851
4201
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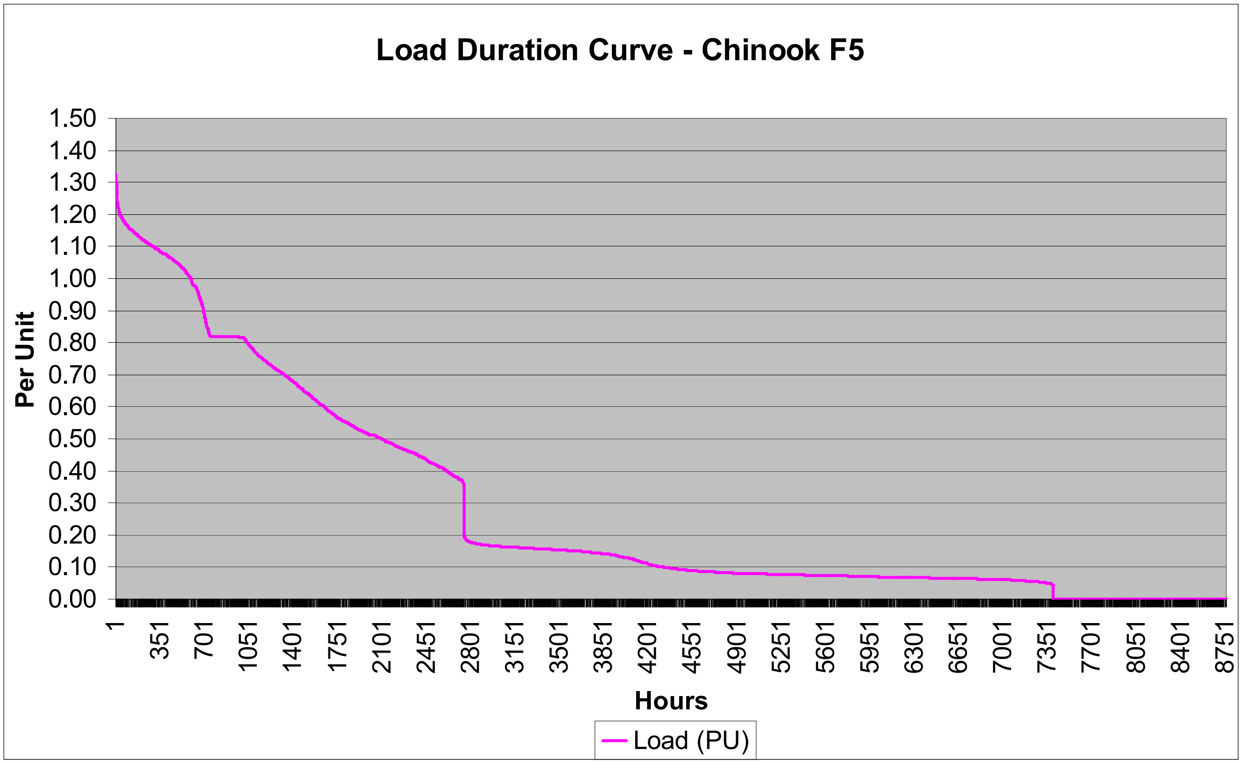
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Chinook F5
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
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2801
3151
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3851
4201
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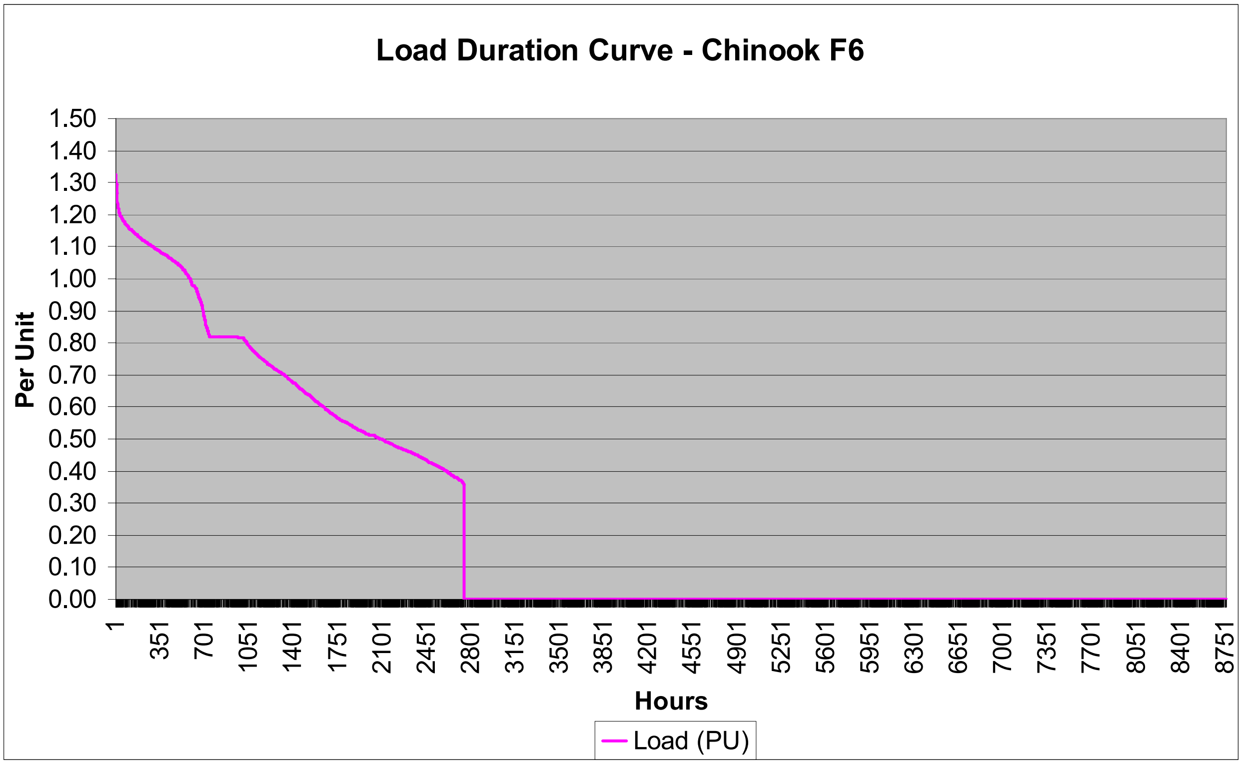
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Chinook F6
Per Unit
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0.80
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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3851
4201
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6651
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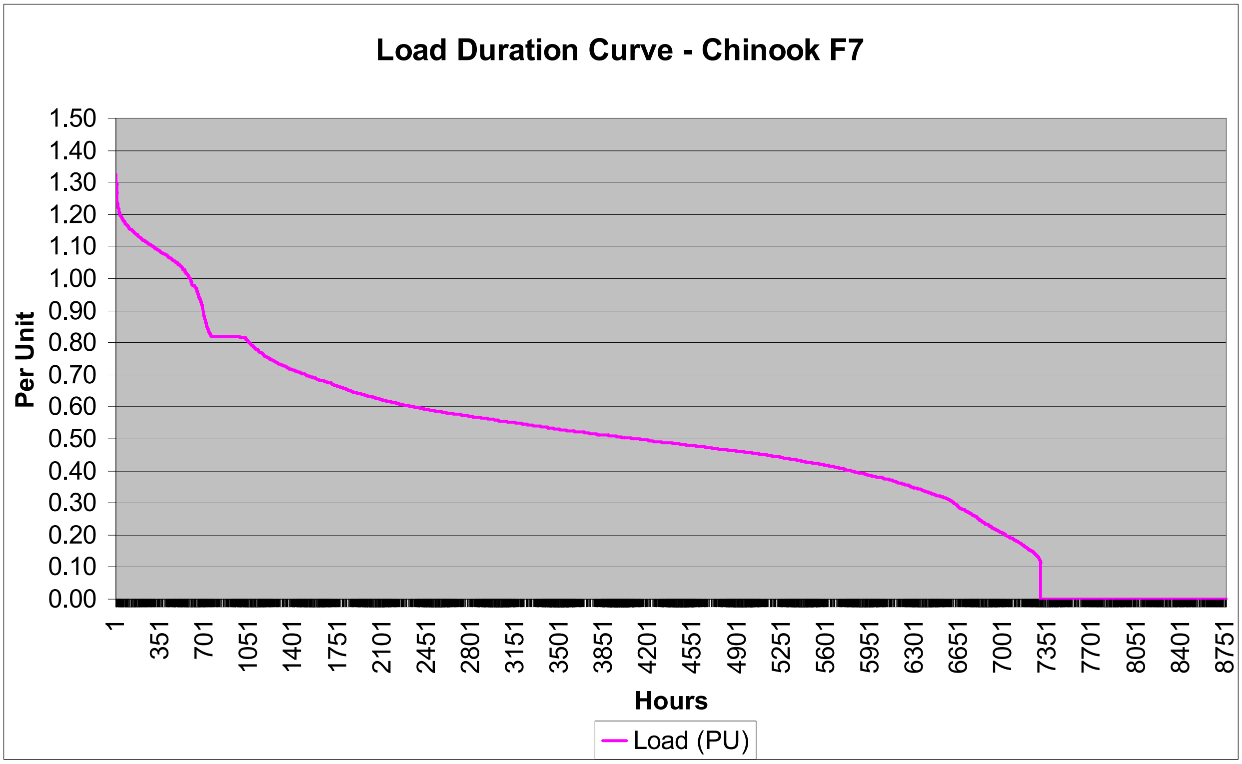
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Chinook F7
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
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3851
4201
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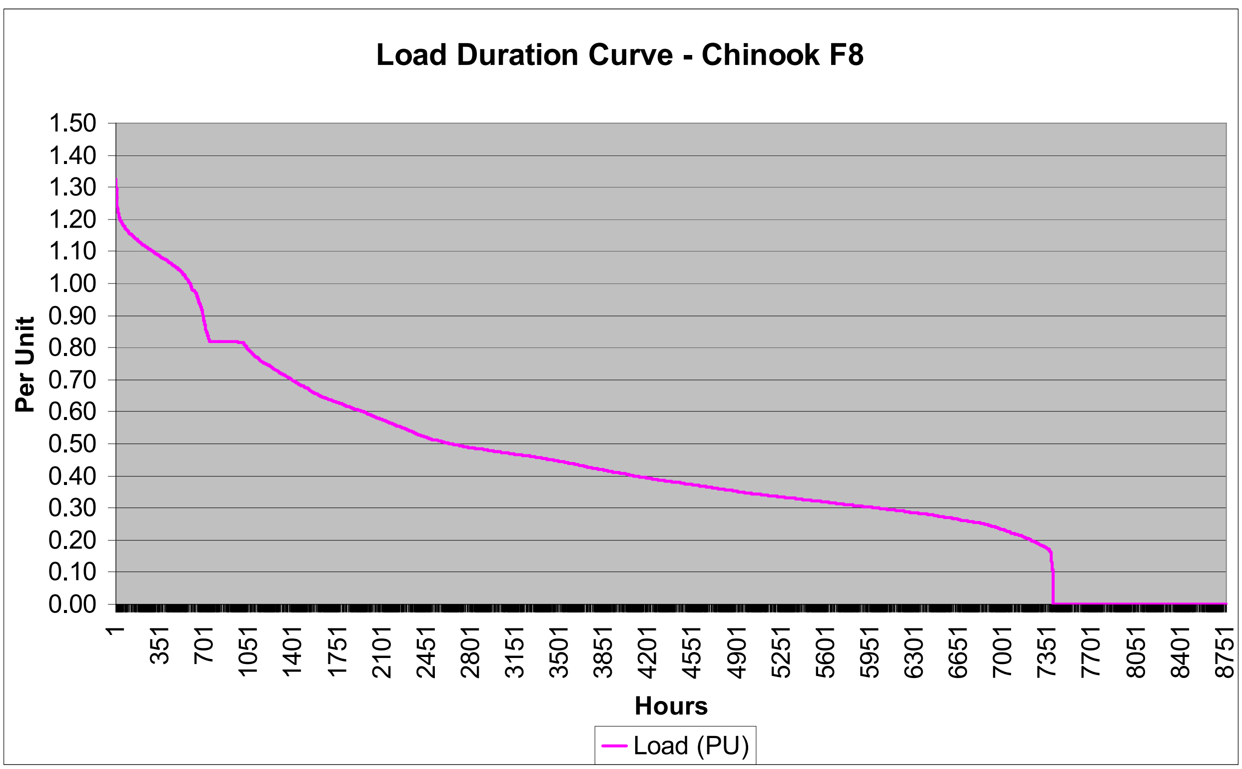
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Chinook F8
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
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701
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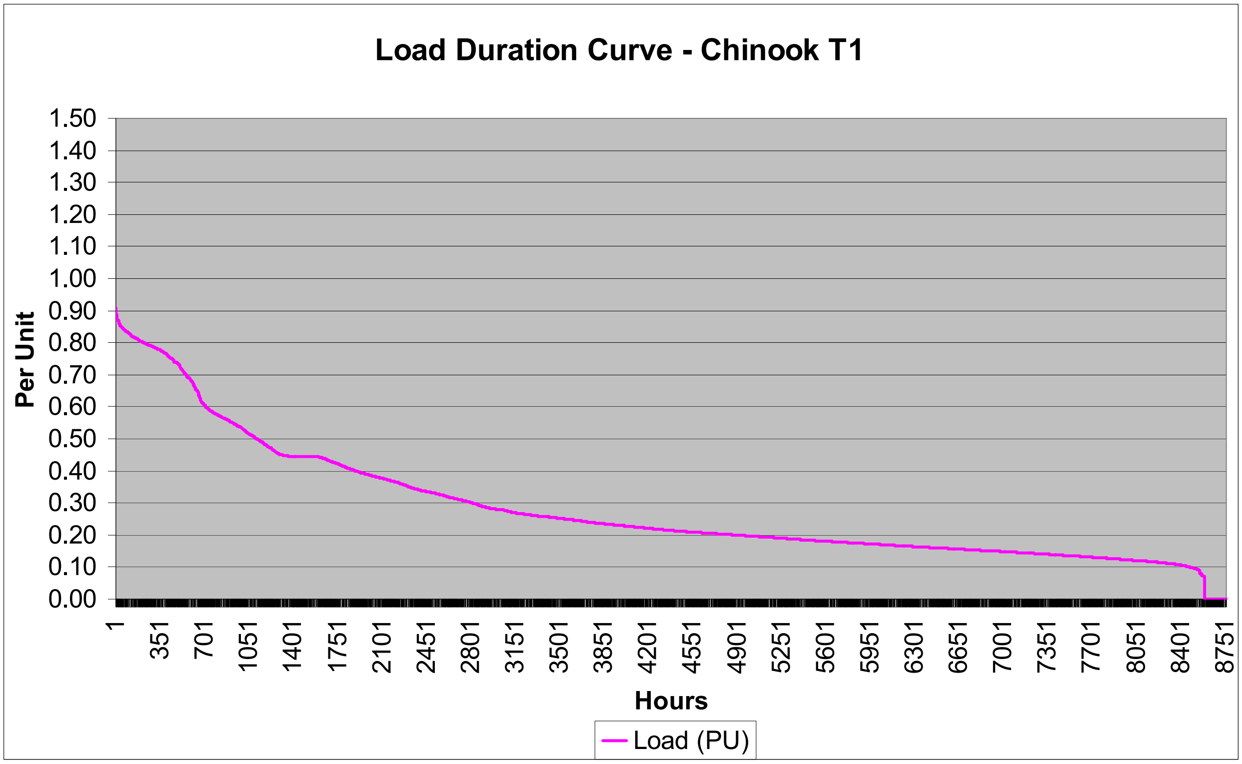
8751
Hours
Load (PU)


Load Duration Curve - Chinook T1
Per Unit
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1.30
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3851
4201
4551
4901
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7351
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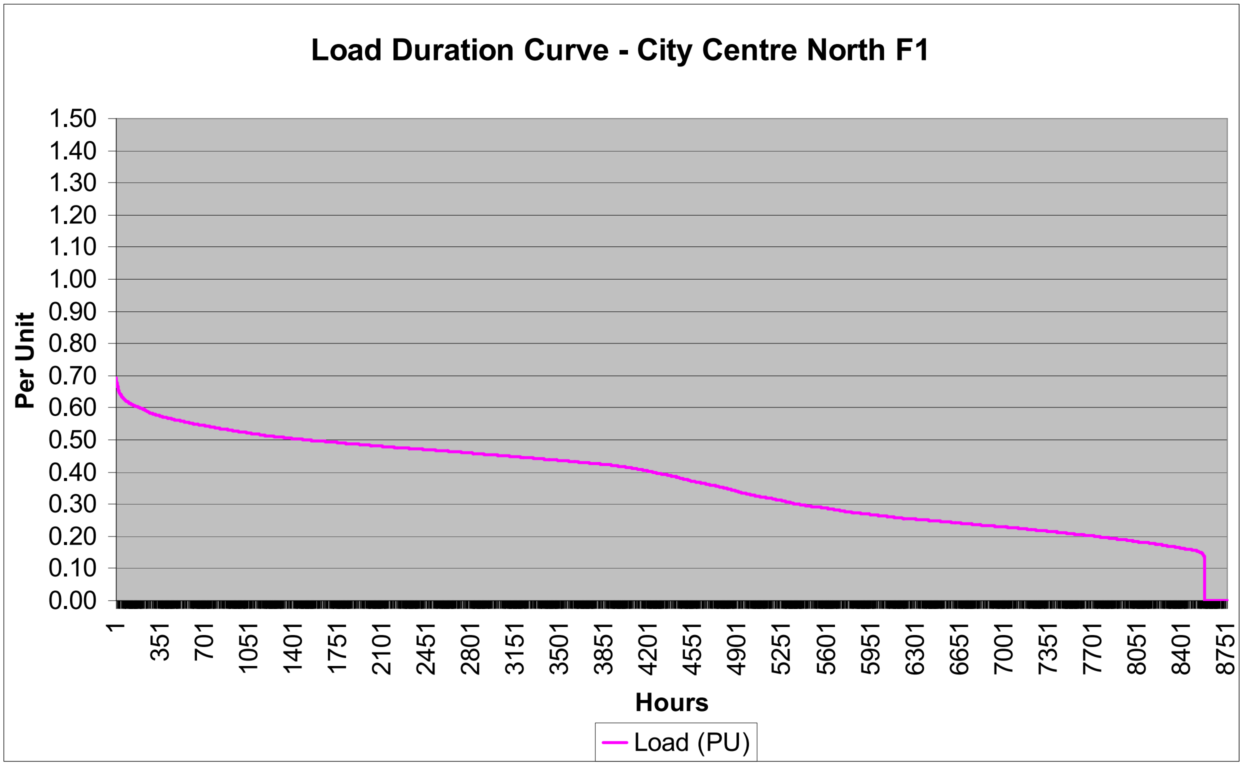
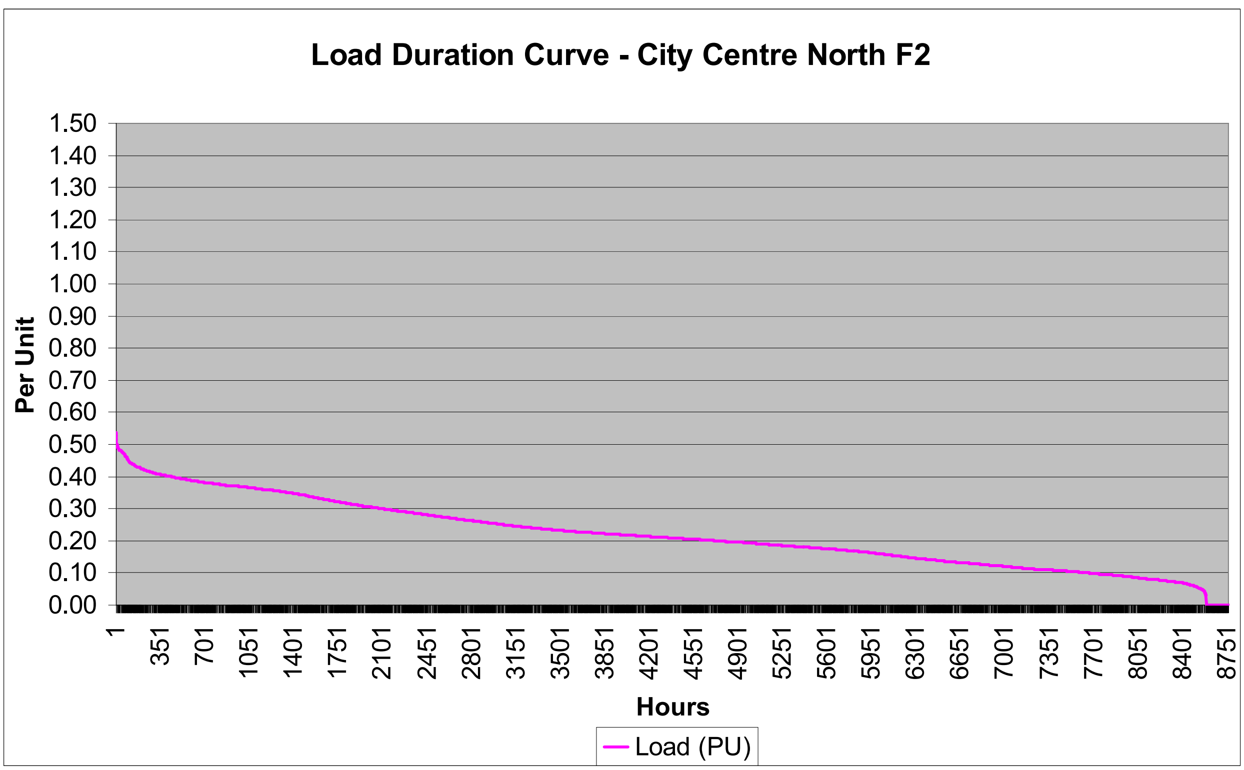
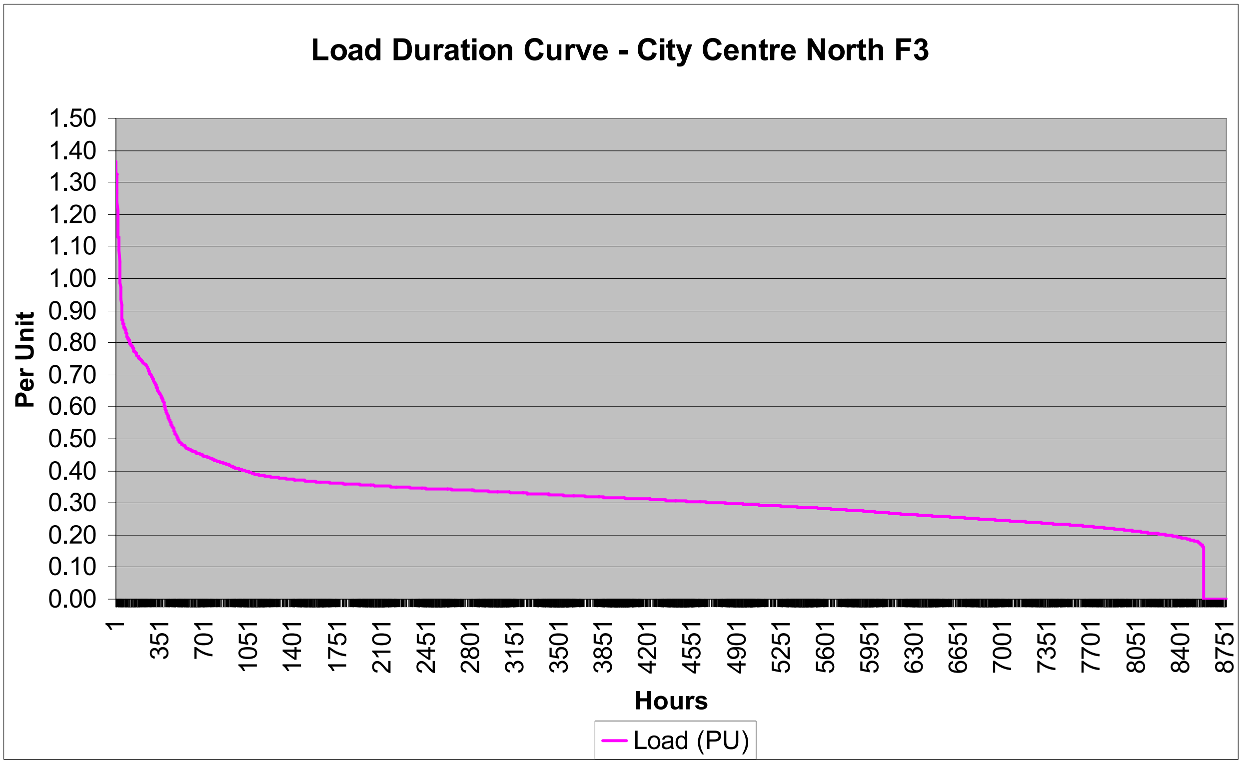
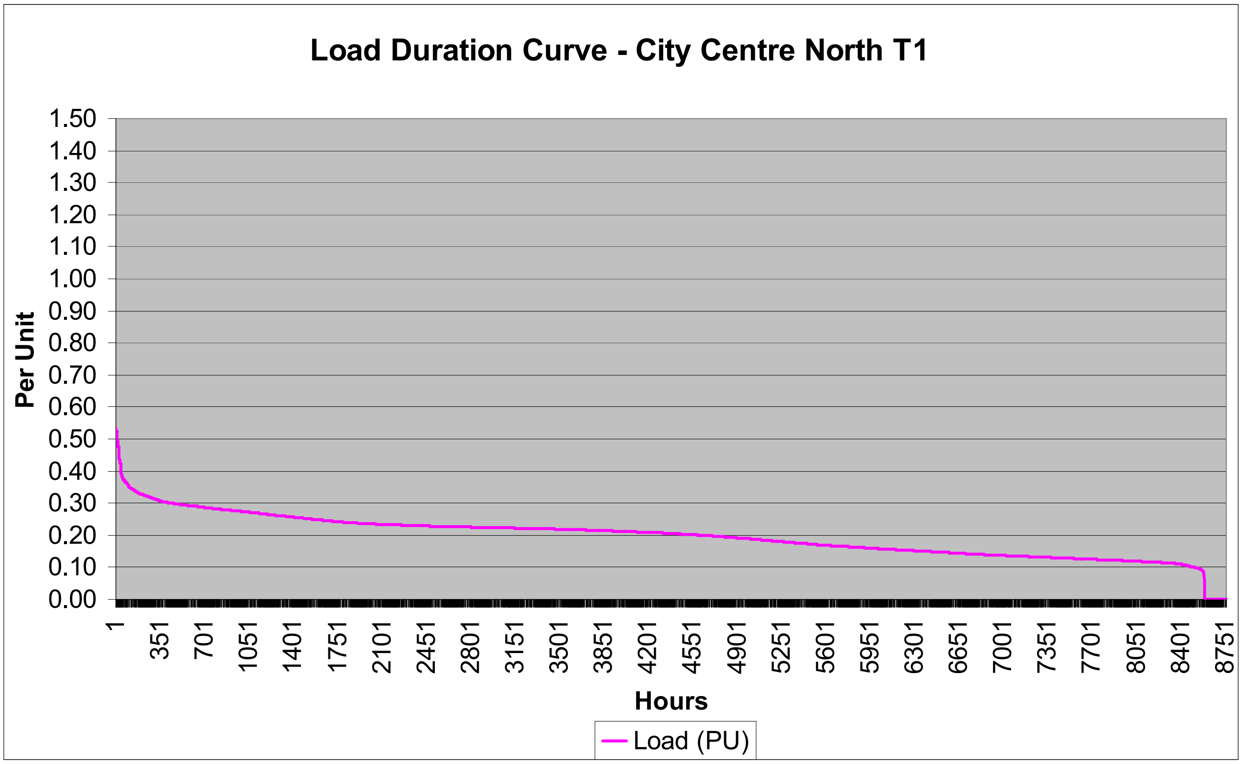
8401
8751
Hours
Load (PU)

City Centre North MS






Load Duration Curve - City Centre North F3
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - City Centre North T1
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1.40
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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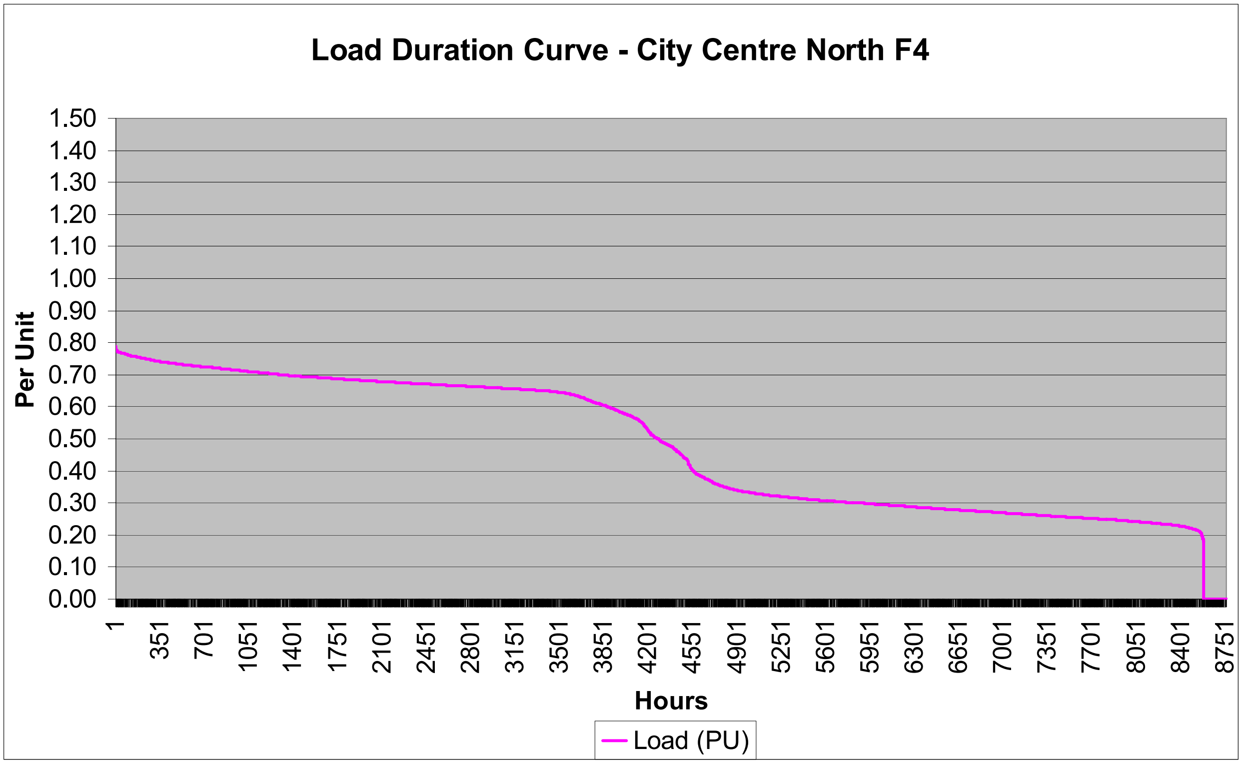
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - City Centre North F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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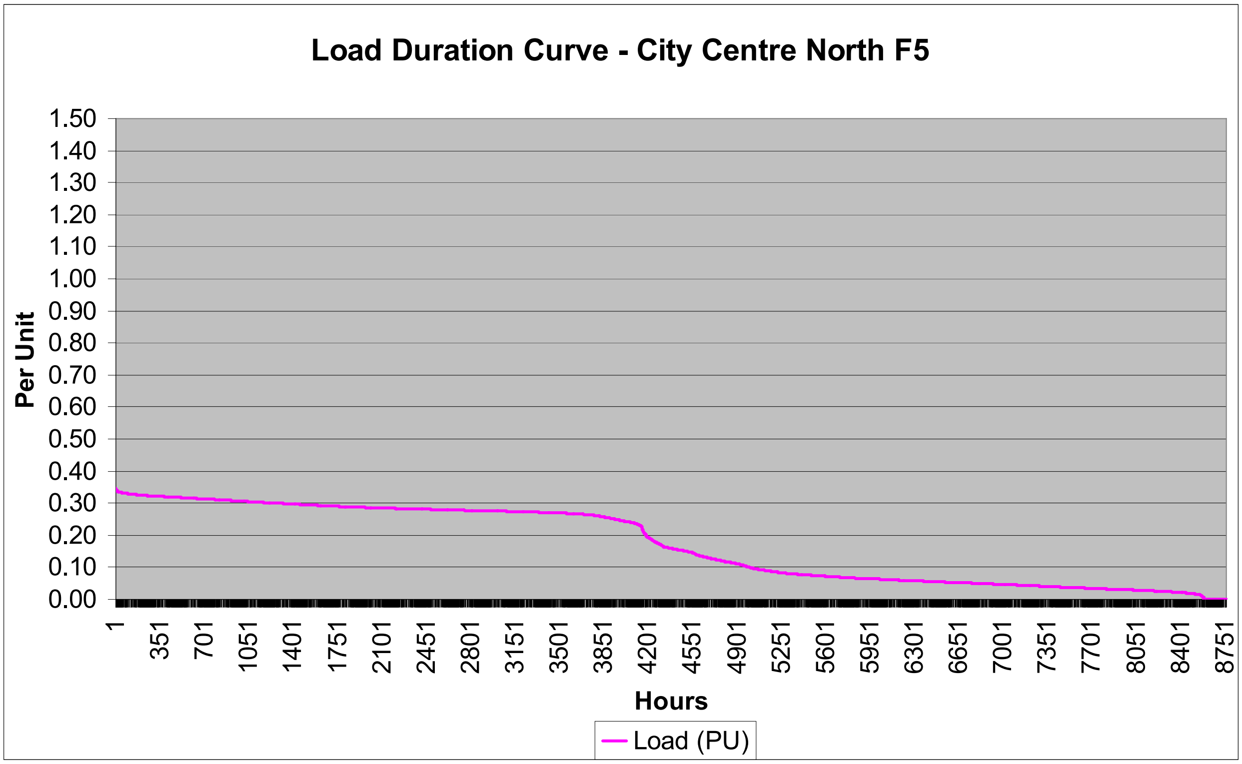
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - City Centre North F5
Per Unit
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1.40
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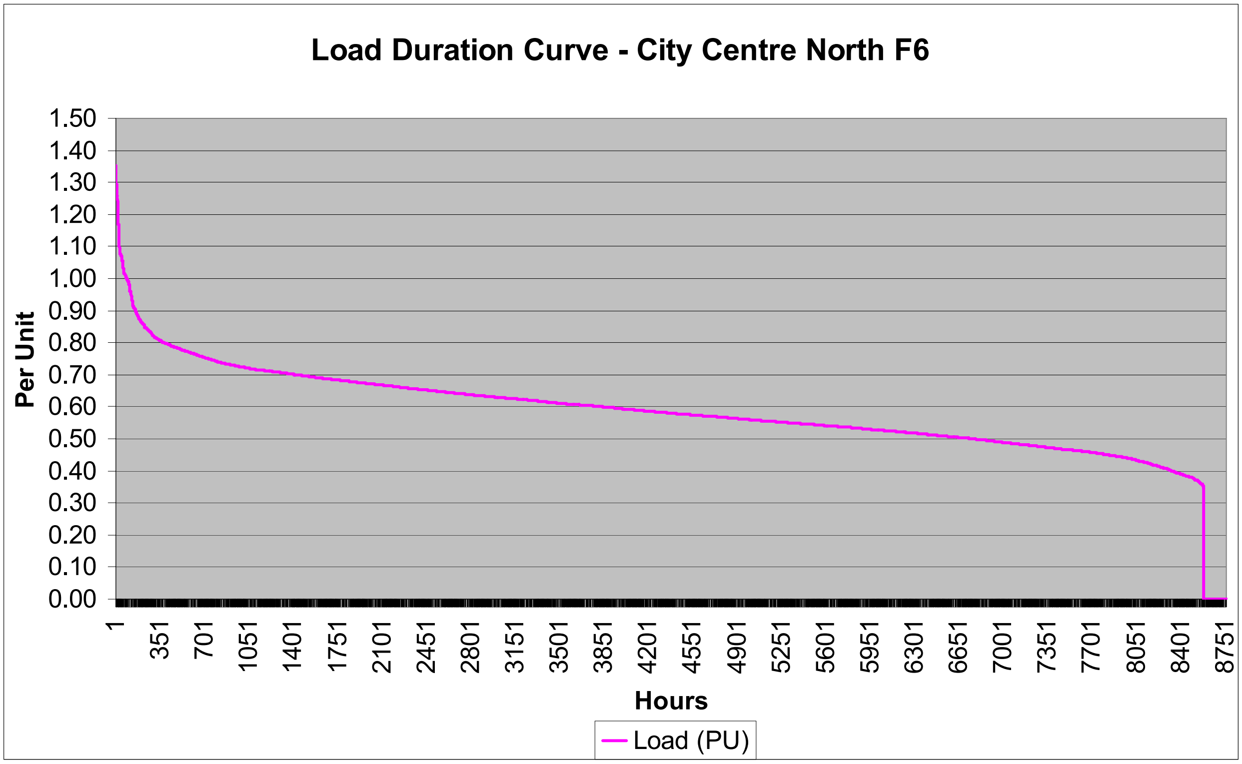
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - City Centre North F6
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1.40
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1.00
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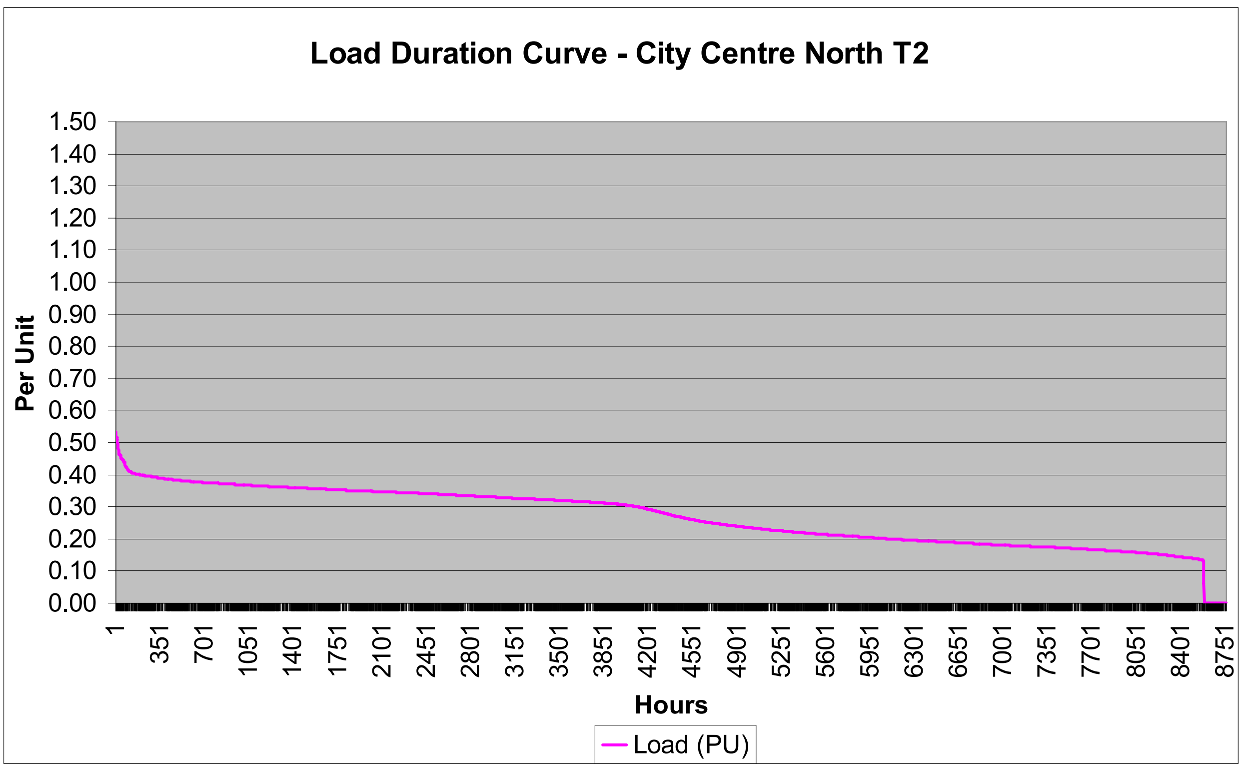
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - City Centre North T2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
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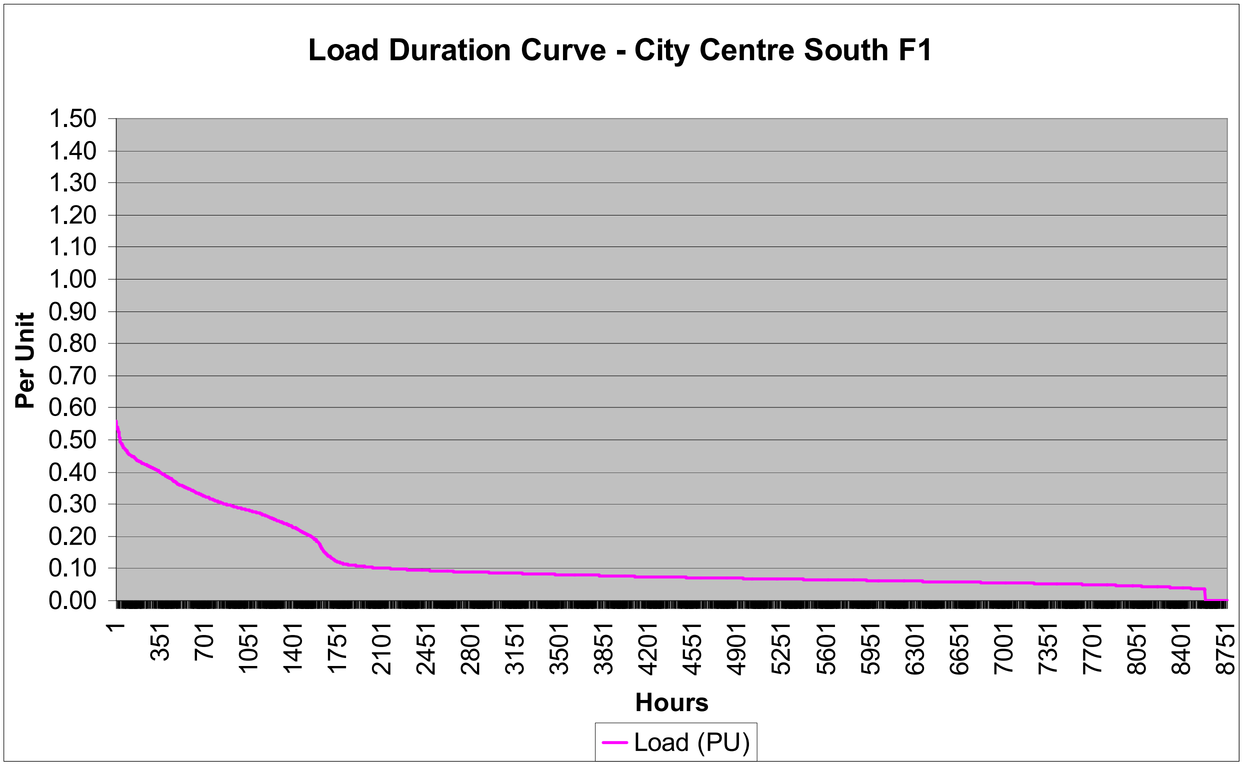
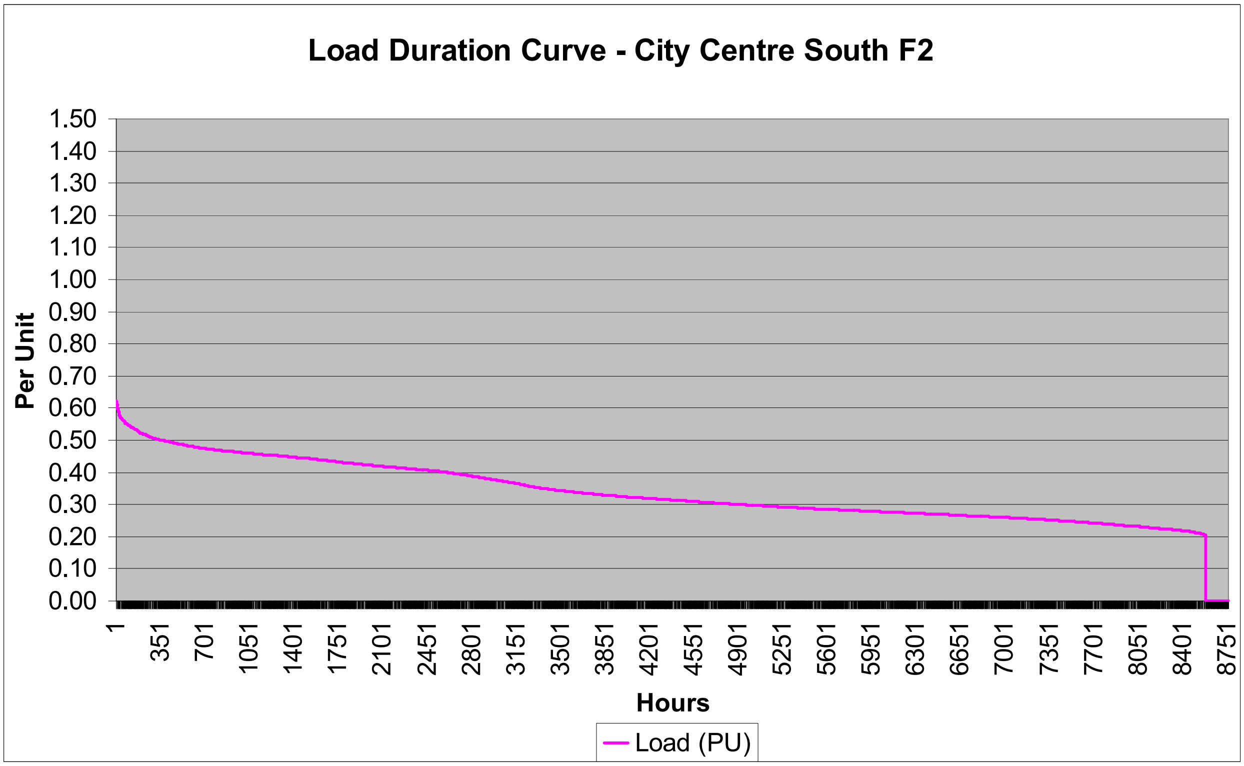
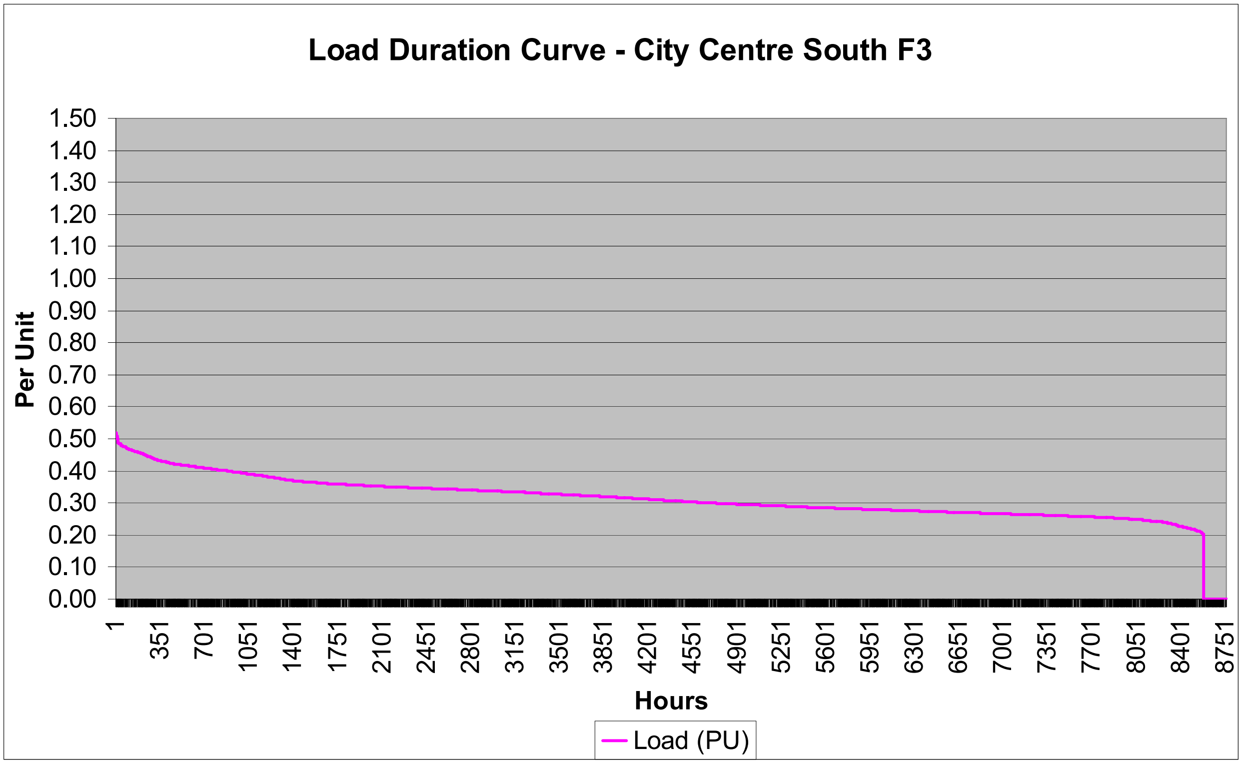
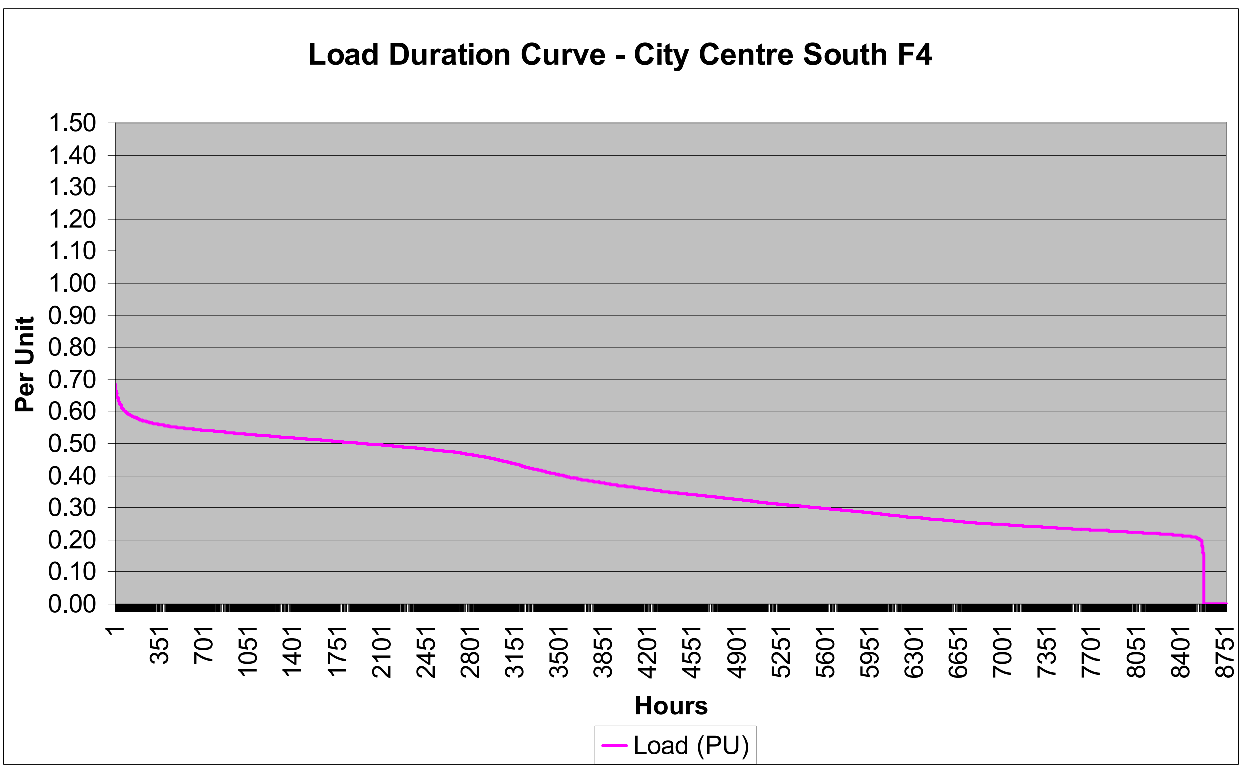
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

City Centre South MS






Load Duration Curve - City Centre South F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - City Centre South F4
Per Unit
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1.40
1.30
1.20
1.10
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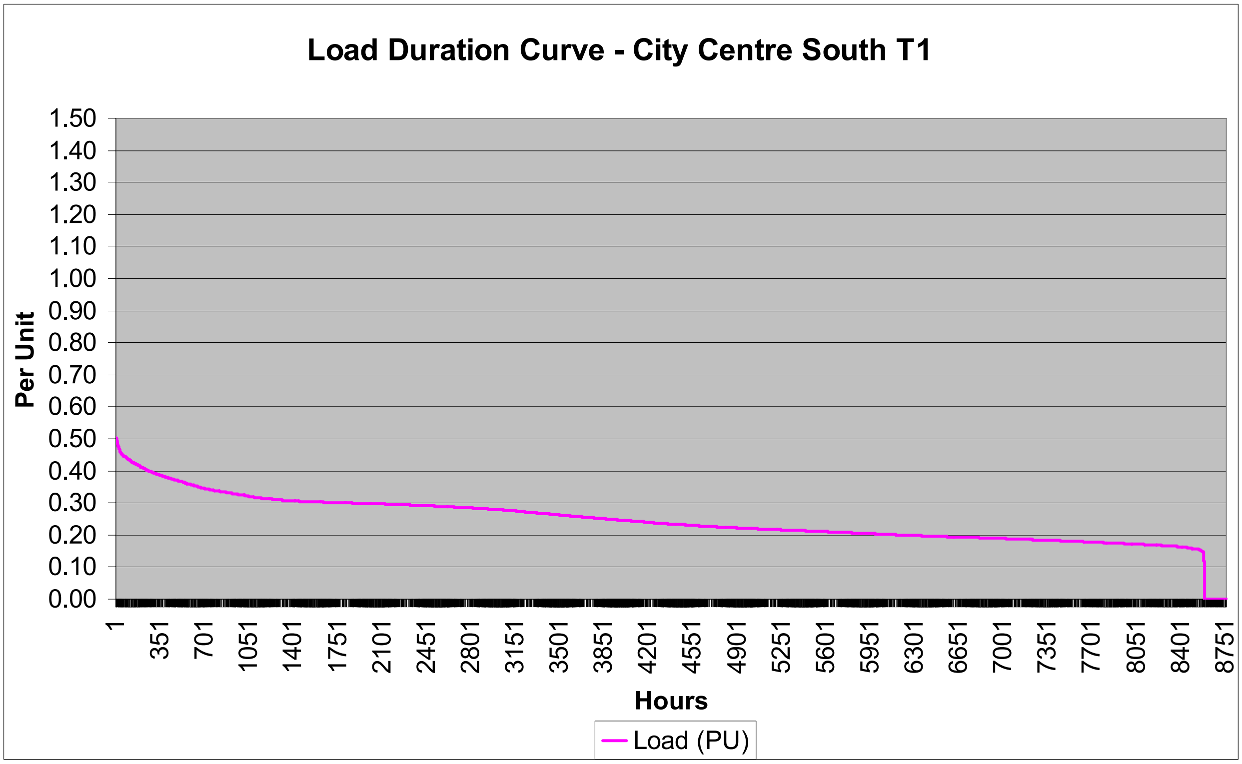
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - City Centre South T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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1401
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3151
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4201
4551
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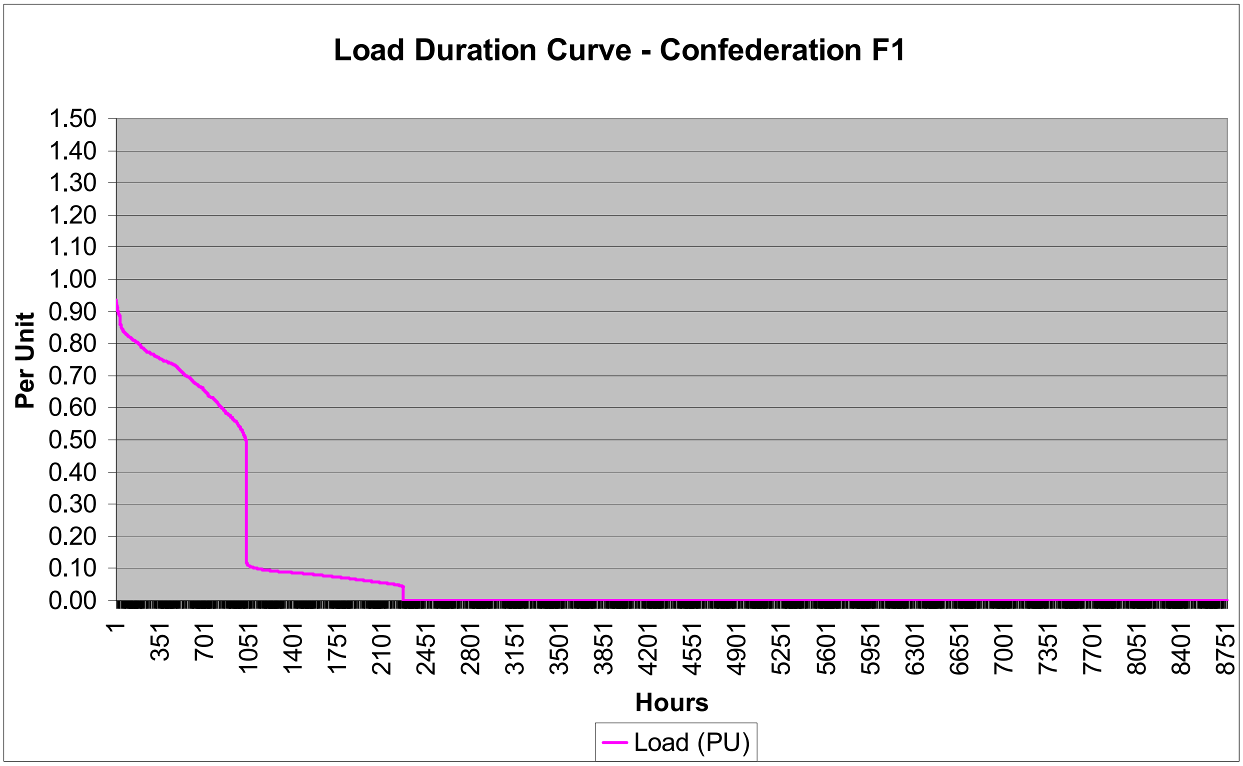
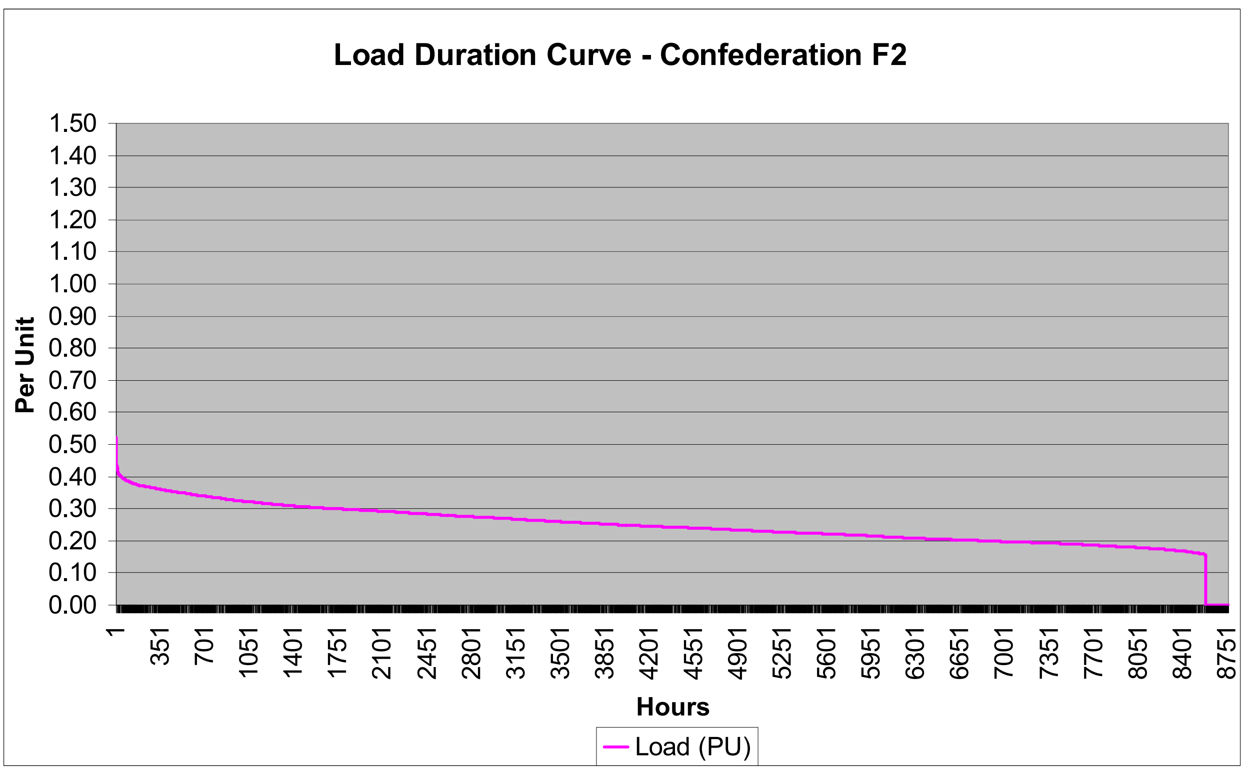
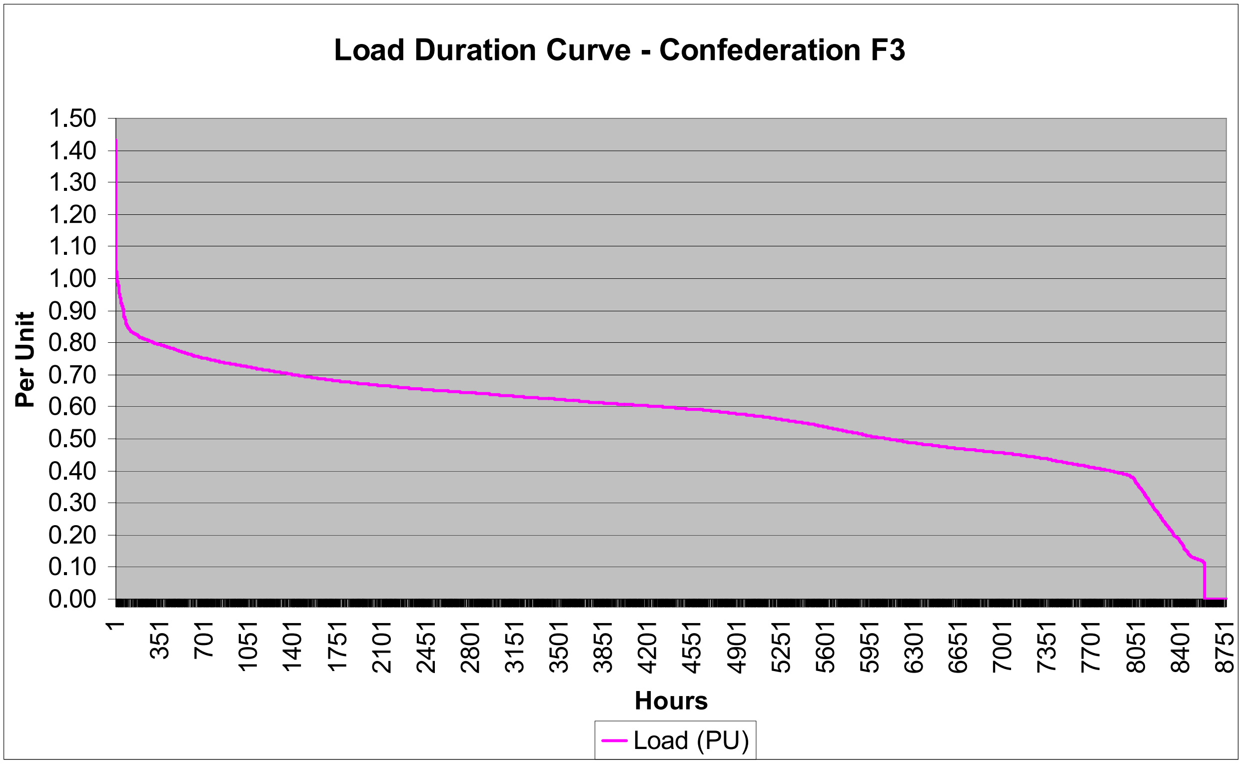
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Confederation MS






Load Duration Curve - Confederation F3
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
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0.60
0.50
0.40
0.30
0.20
0.10
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4201
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8051
8401
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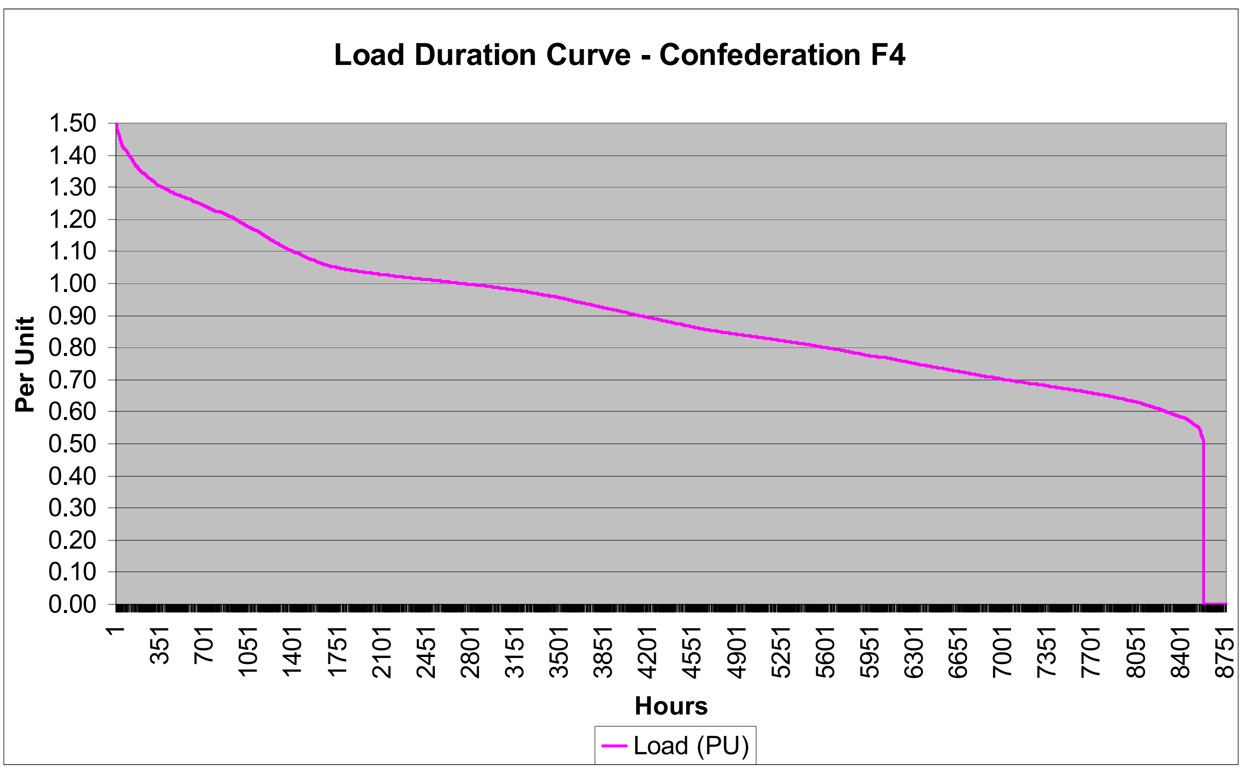
Hours
Load (PU)


Load Duration Curve - Confederation F4
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
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3151
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4201
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6301
6651
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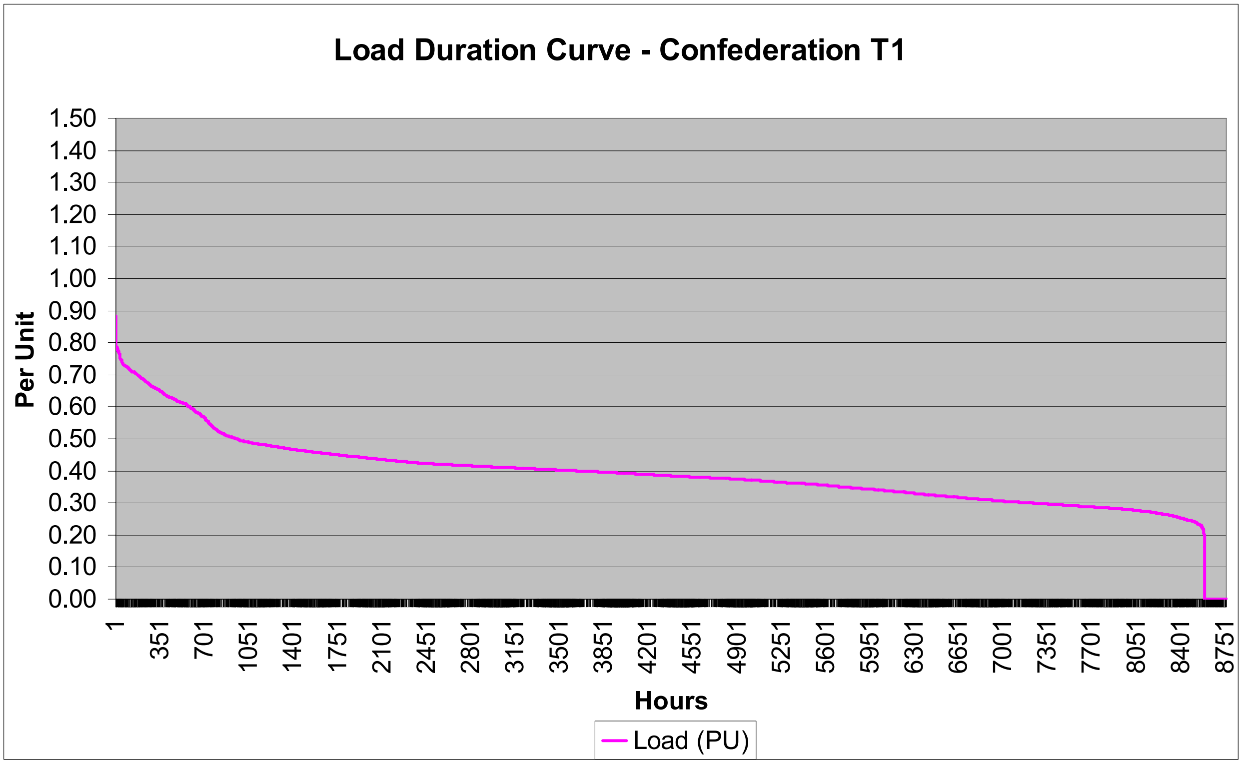
8401
8751
Hours
Load (PU)


Load Duration Curve - Confederation T1
Per Unit
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
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3151
3501
3851
4201
4551
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7351
7701
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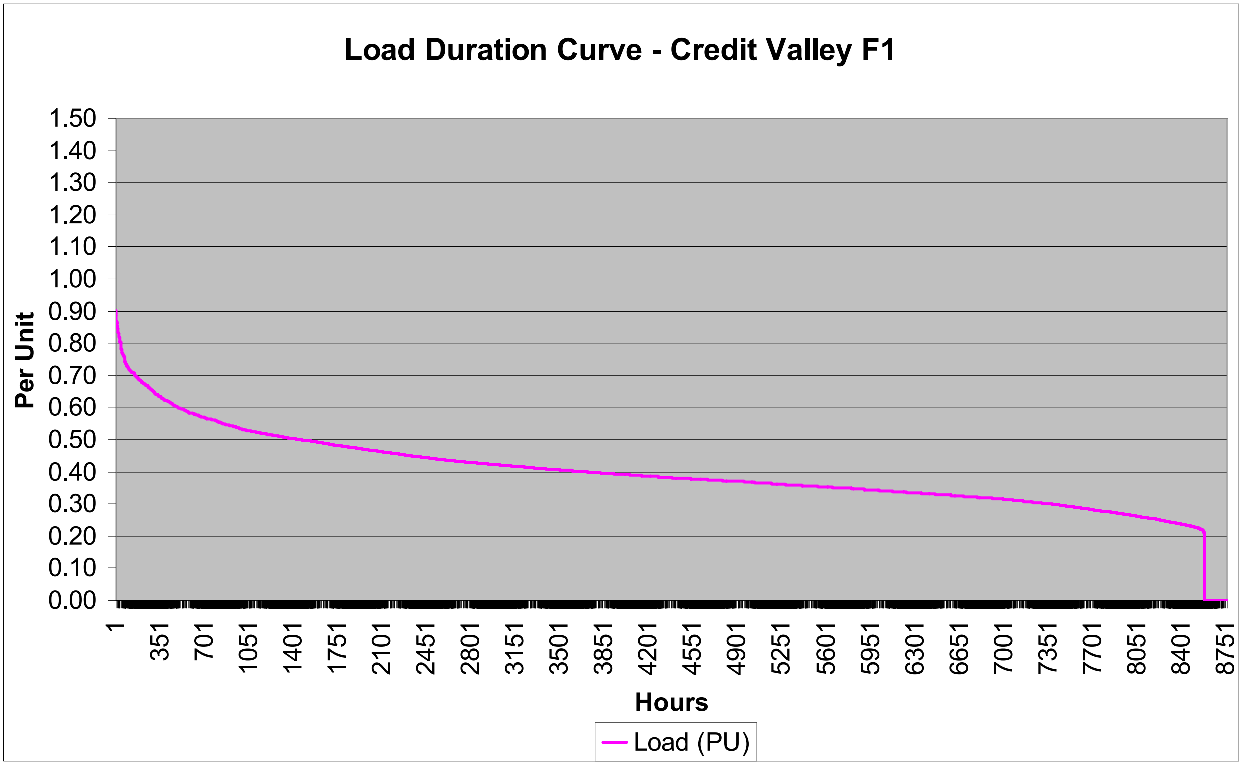
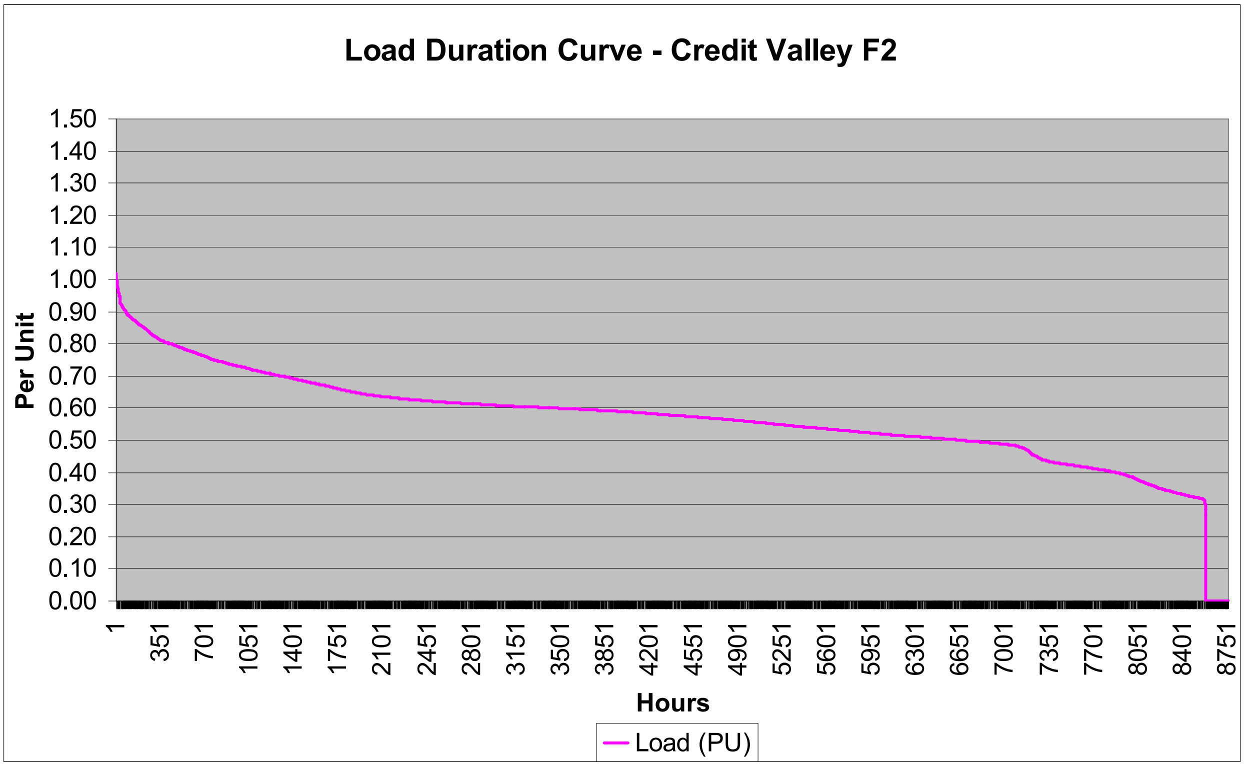
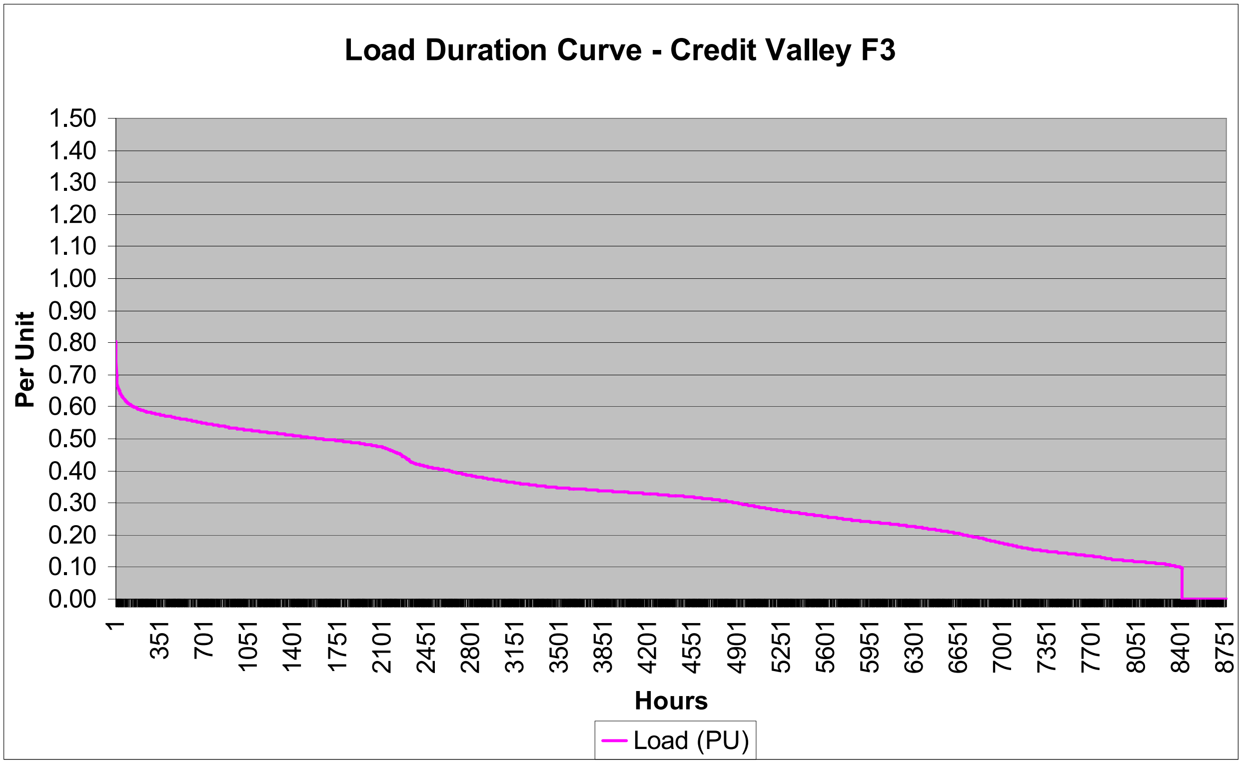
8401
8751
Hours
Load (PU)

Credit Valley MS







Load Duration Curve - Credit Valley F3
Per Unit
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1.30
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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701
1051
1401
1751
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4201
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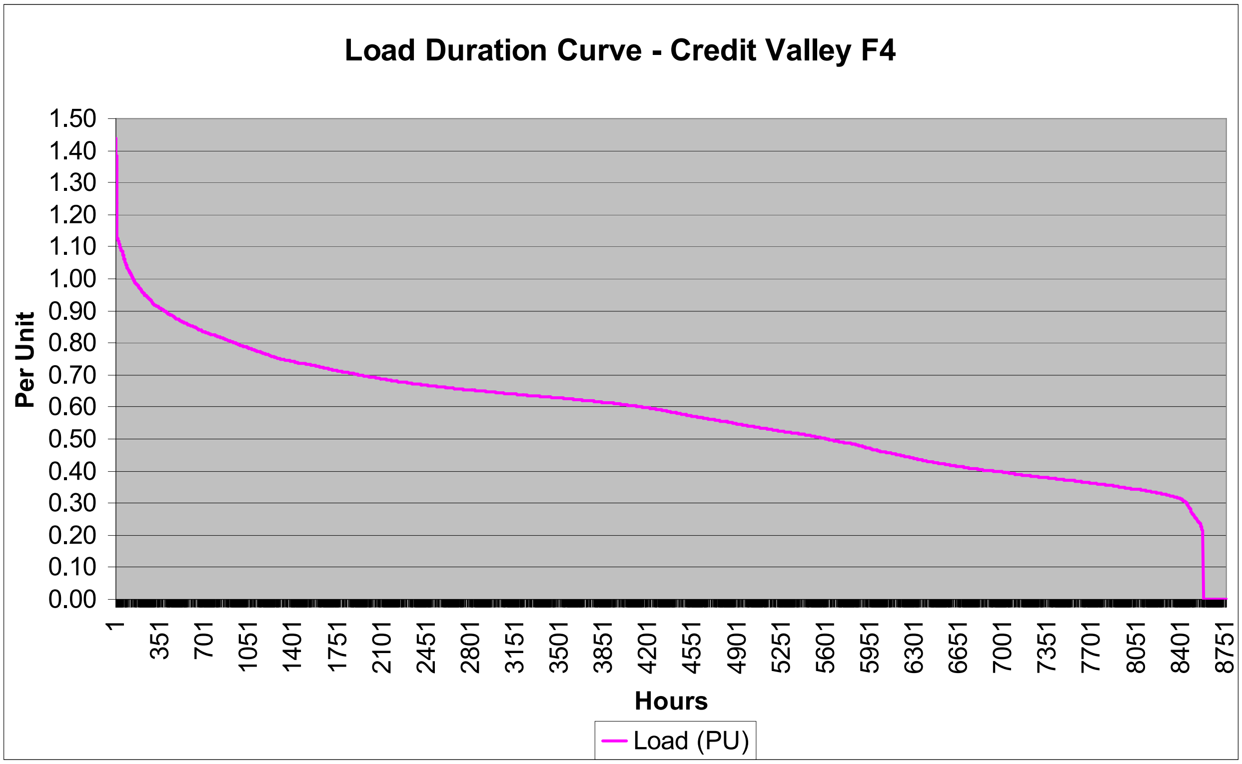
Hours
Load (PU)



Load Duration Curve - Credit Valley F4
Per Unit
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1.00
0.90
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0.60
0.50
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0.30
0.20
0.10
0.00
1
351
701
1051
1401
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2451
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3151
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3851
4201
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8051
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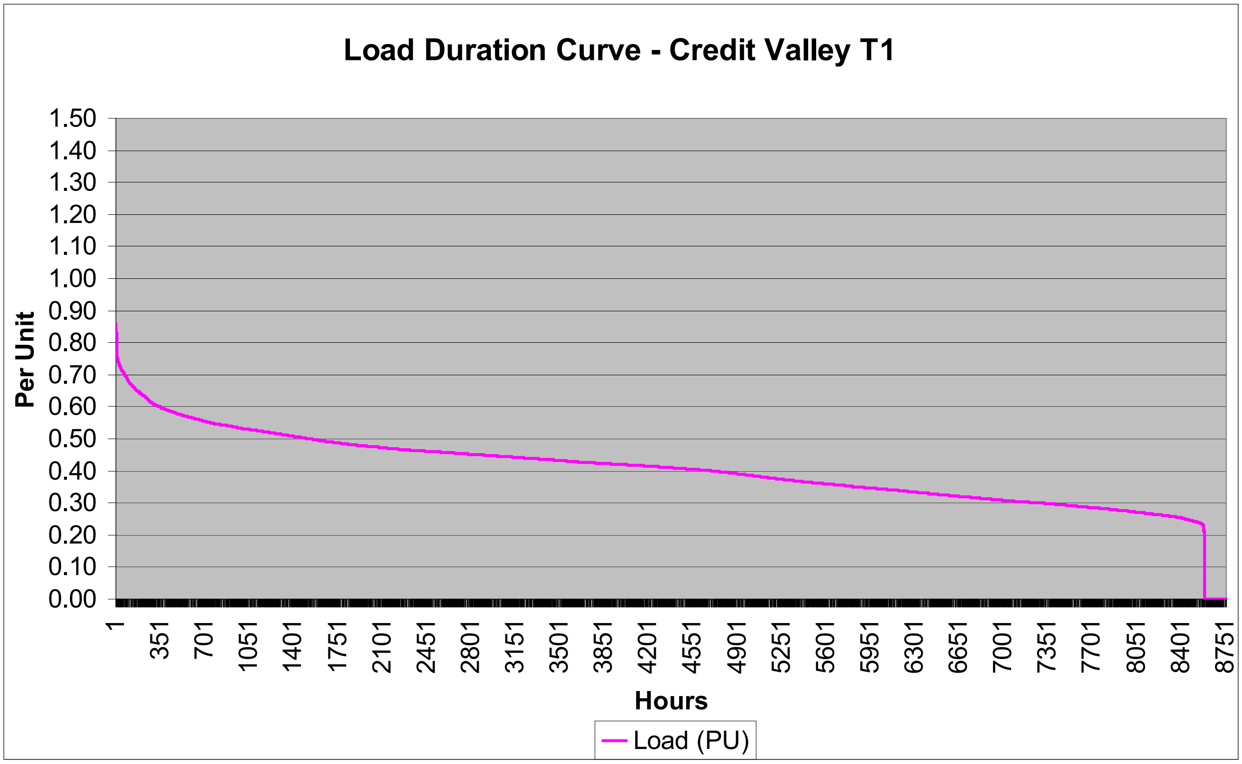
8751
Hours
Load (PU)



Load Duration Curve - Credit Valley T1
Per Unit
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1.10
1.00
0.90
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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1401
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3501
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4201
4551
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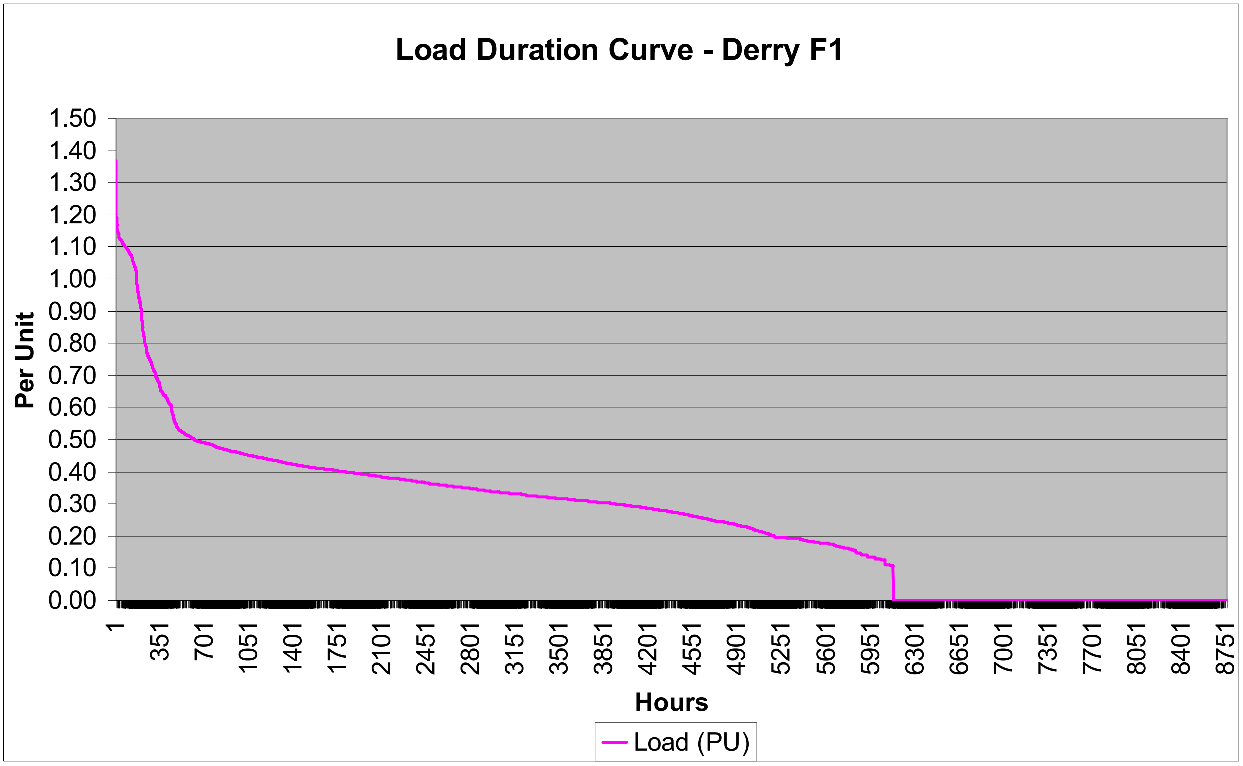
8051
8401
8751
Hours
Load (PU)

Derry MS



Load Duration Curve - Derry F1
Per Unit
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1.10
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0.60
0.50
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0.10
0.00
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2101
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3151
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4201
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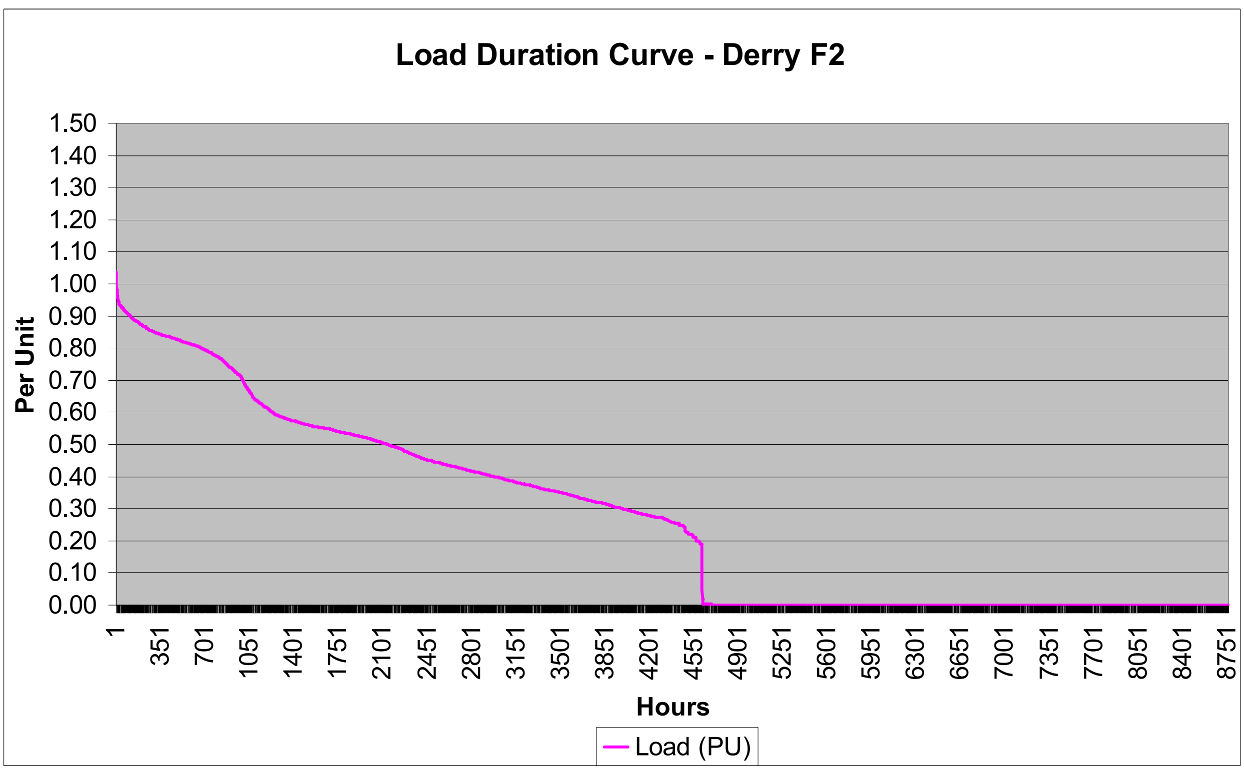
8401
8751
Hours
Load (PU)



Load Duration Curve - Derry F2
Per Unit
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0.60
0.50
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0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
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3151
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3851
4201
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6651
7001
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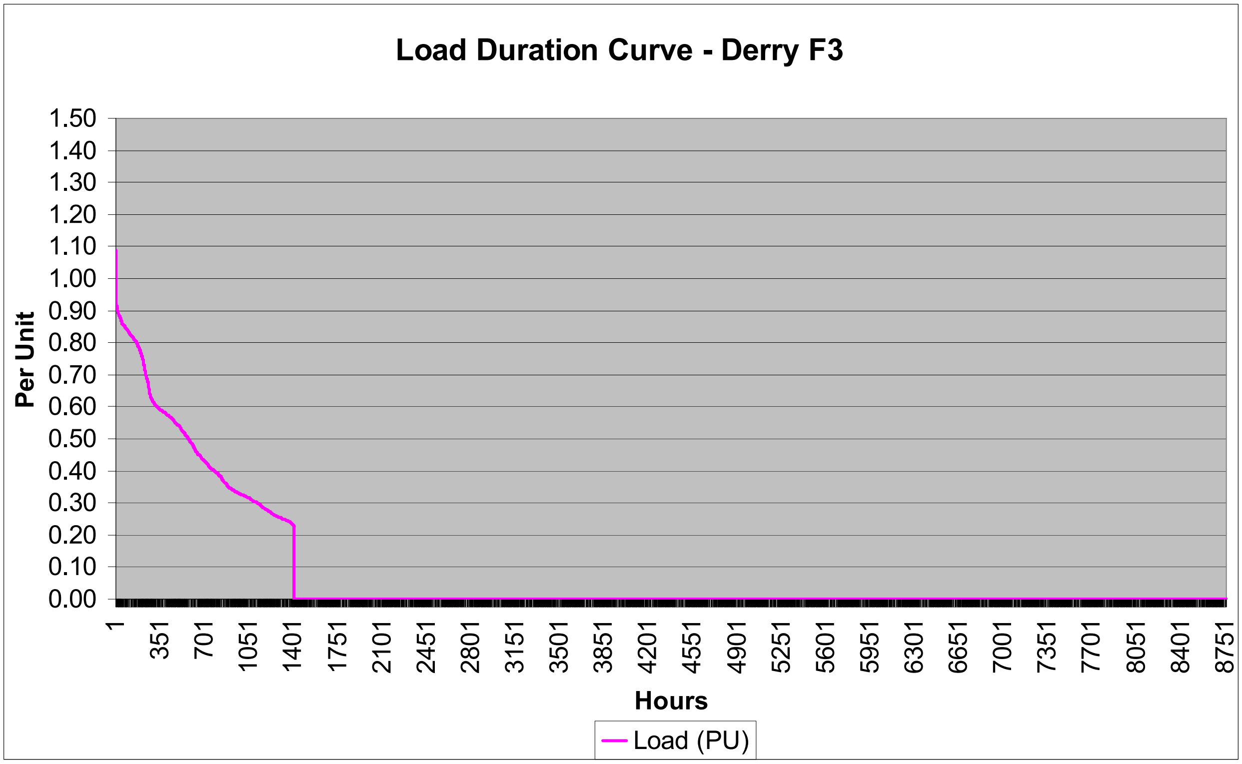
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Derry F3
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
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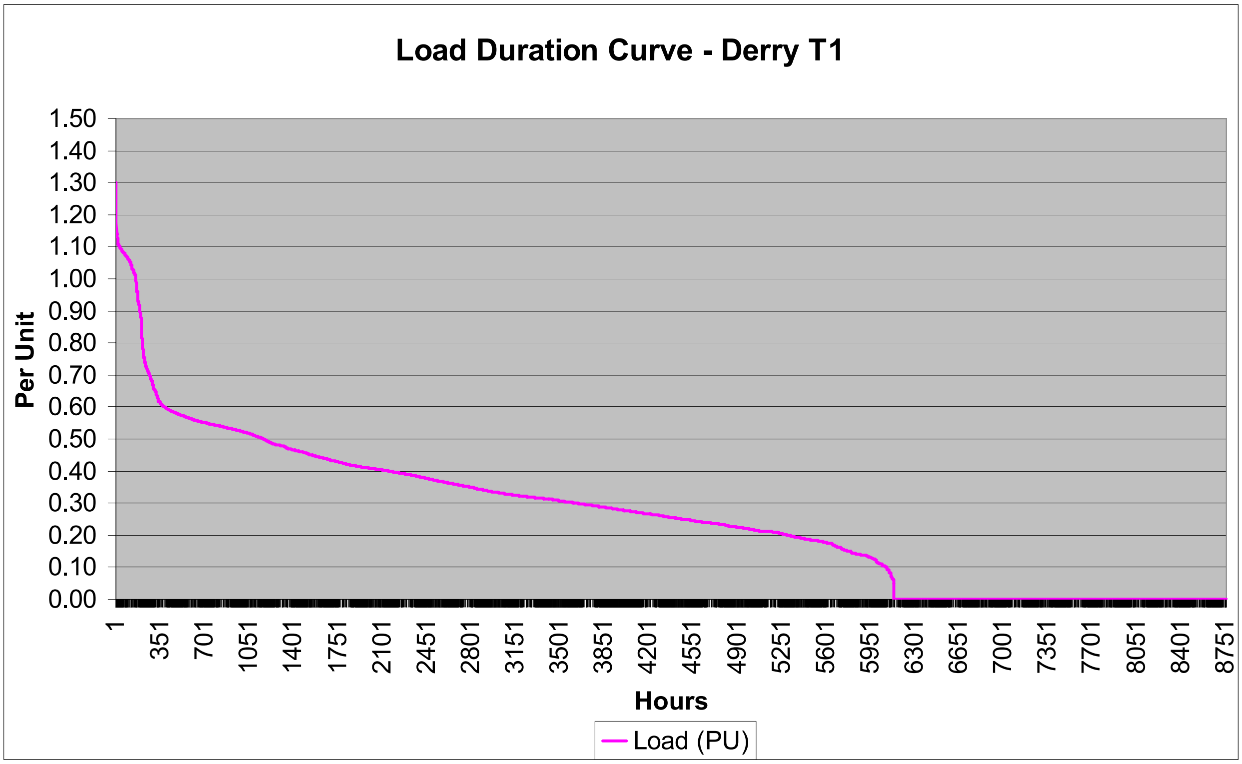
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Derry T1
Per Unit
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0.80
0.70
0.60
0.50
0.40
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0.10
0.00
1
351
701
1051
1401
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3851
4201
4551
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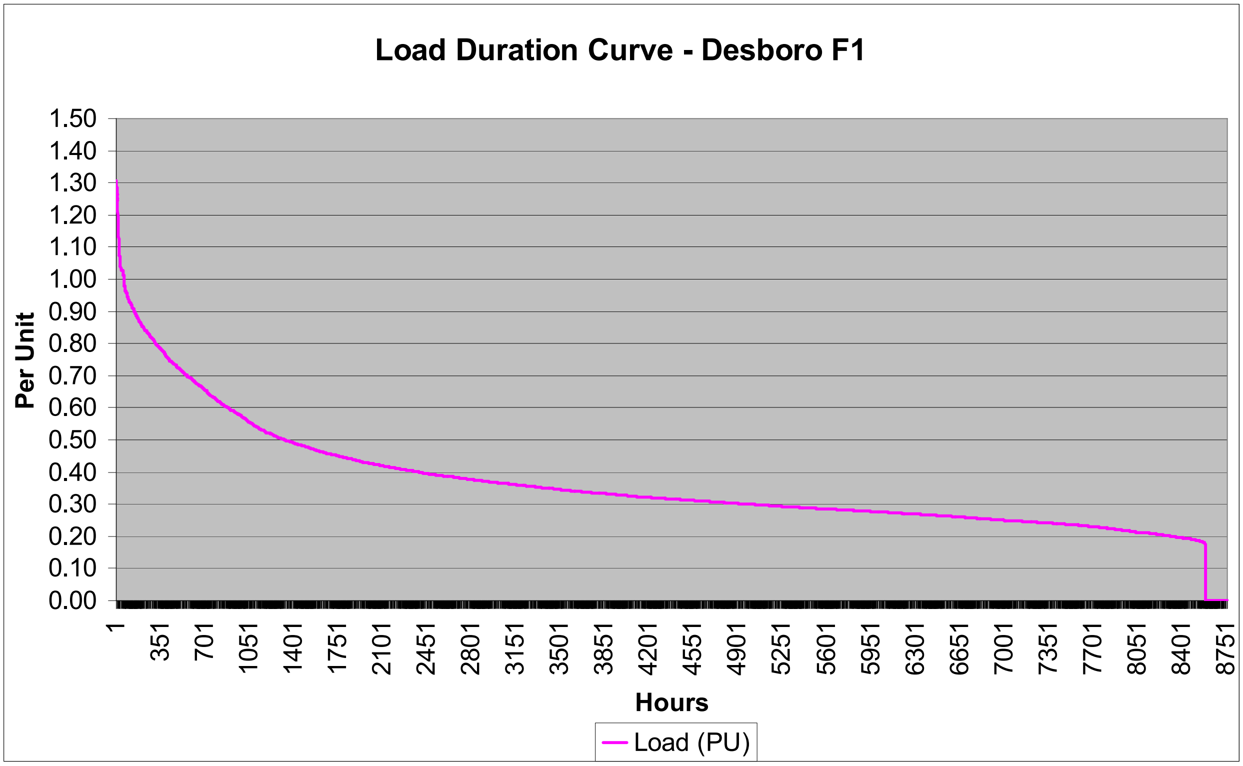
7701
8051
8401
8751
Hours
Load (PU)

Desboro MS


Load Duration Curve - Desboro F1
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1.00
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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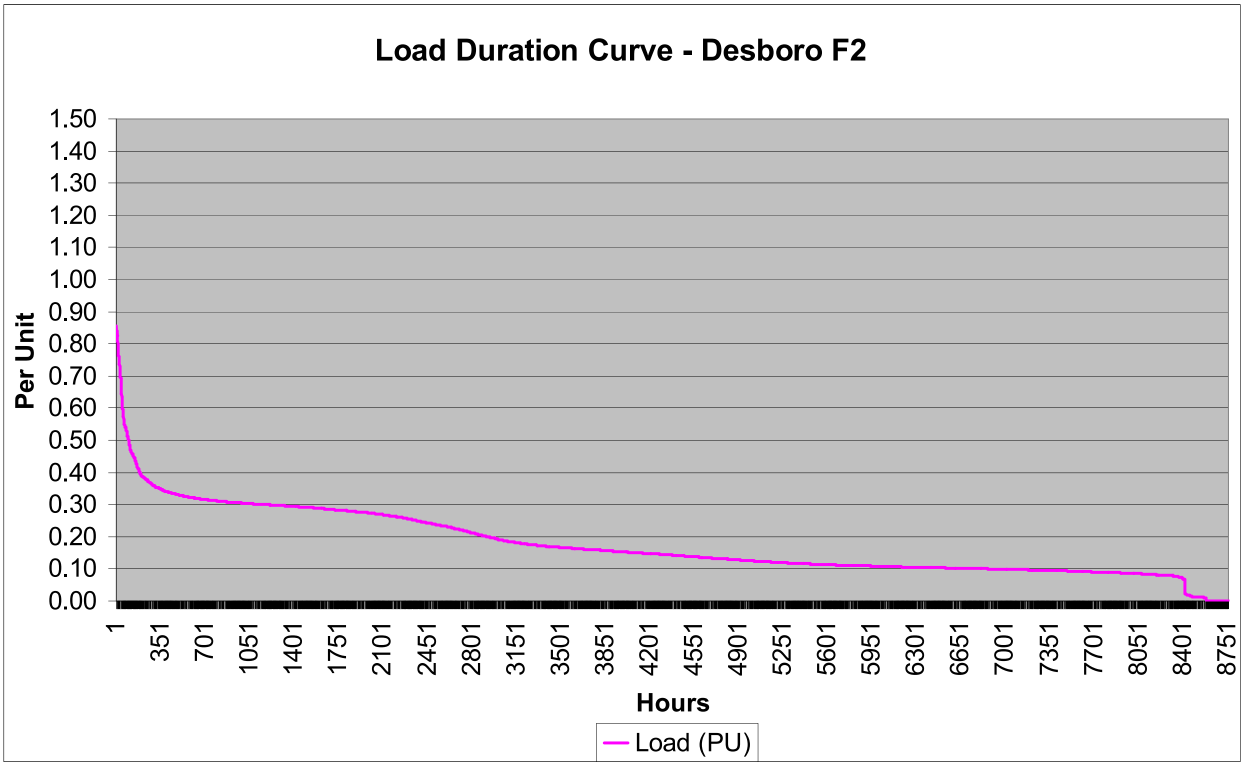
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Desboro F2
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0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
7001
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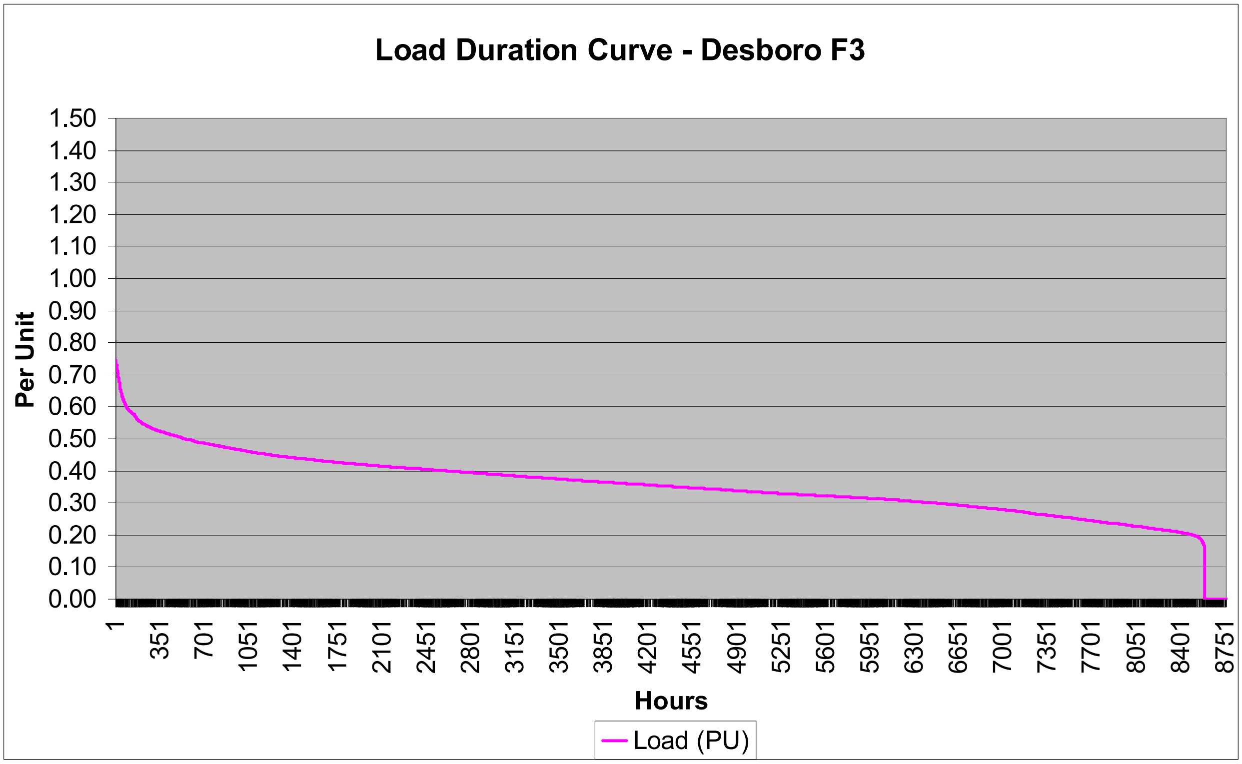
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Desboro F3
Per Unit
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1.30
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
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4201
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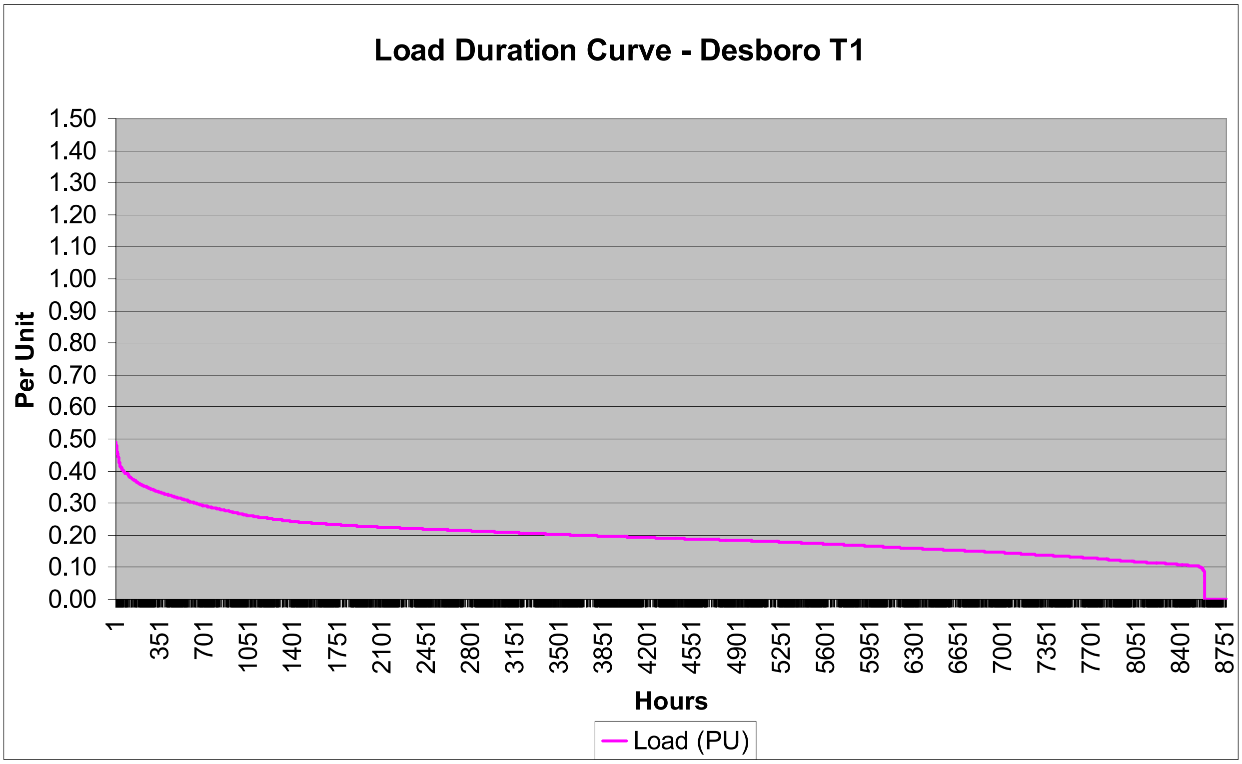
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Desboro T1
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
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3851
4201
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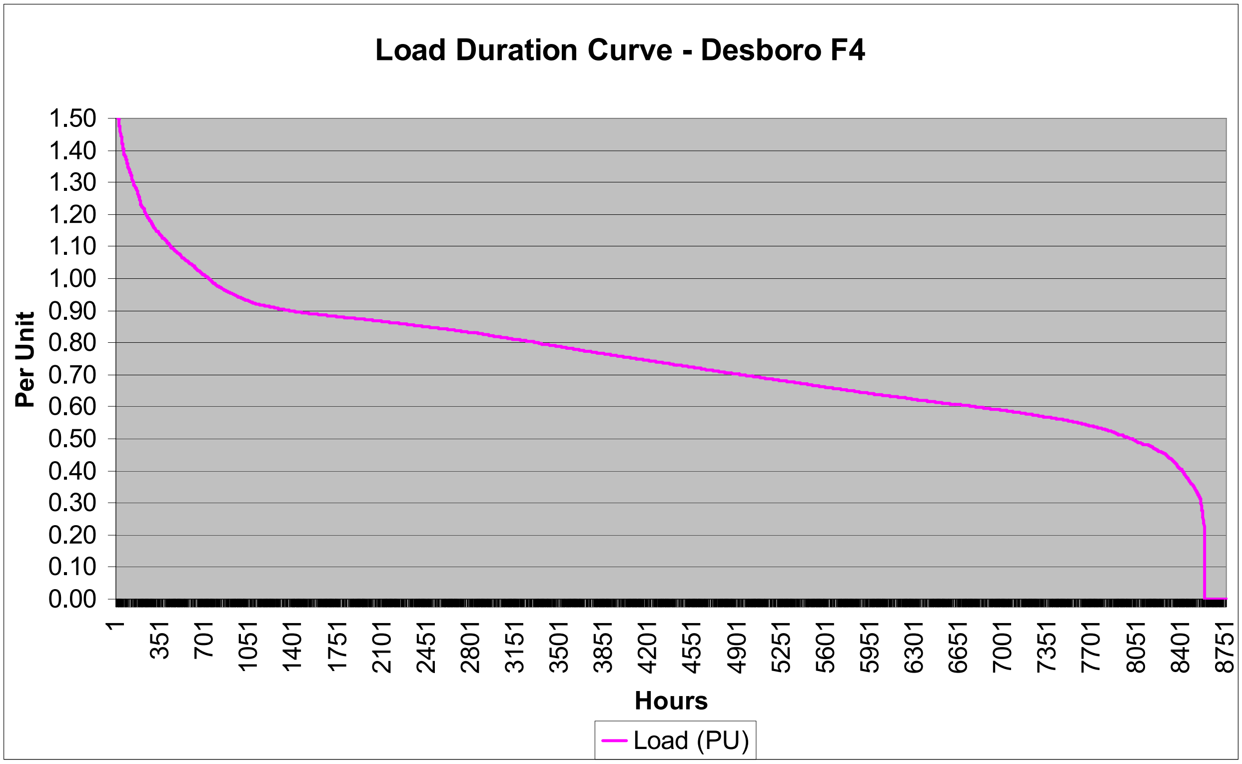
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Desboro F4
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5601
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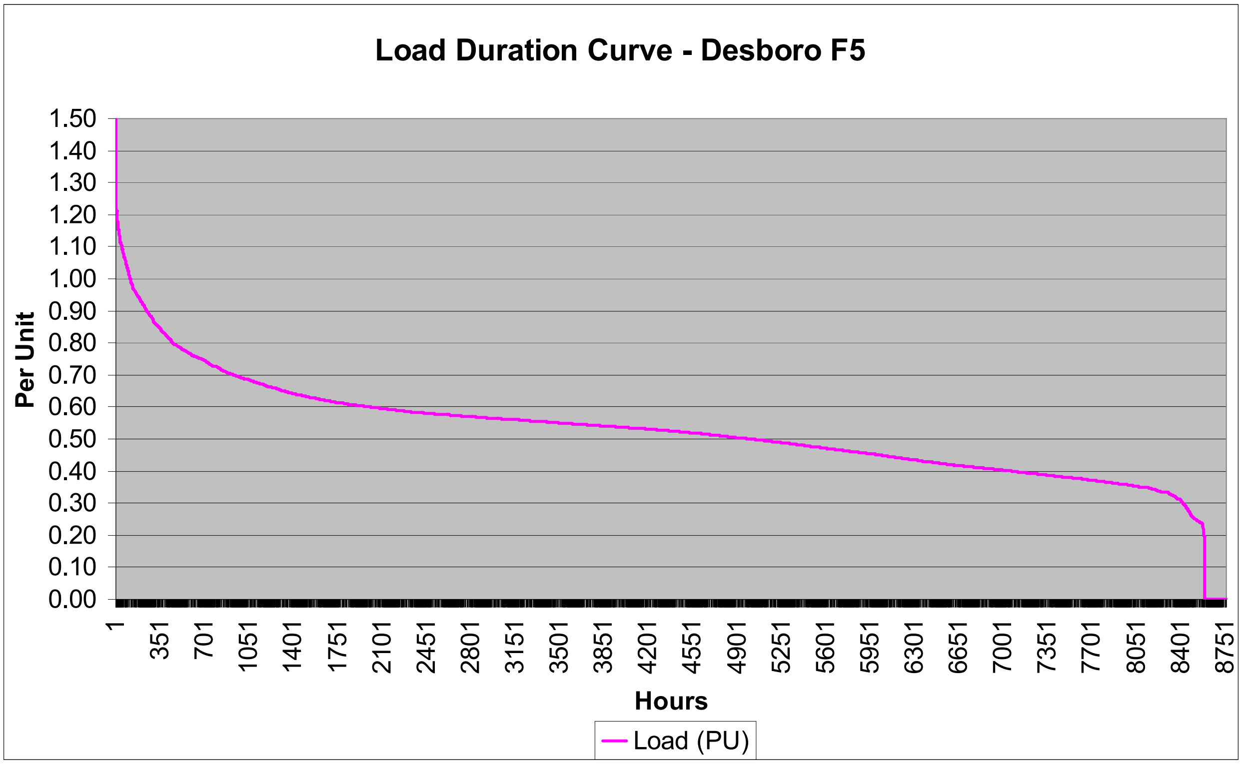
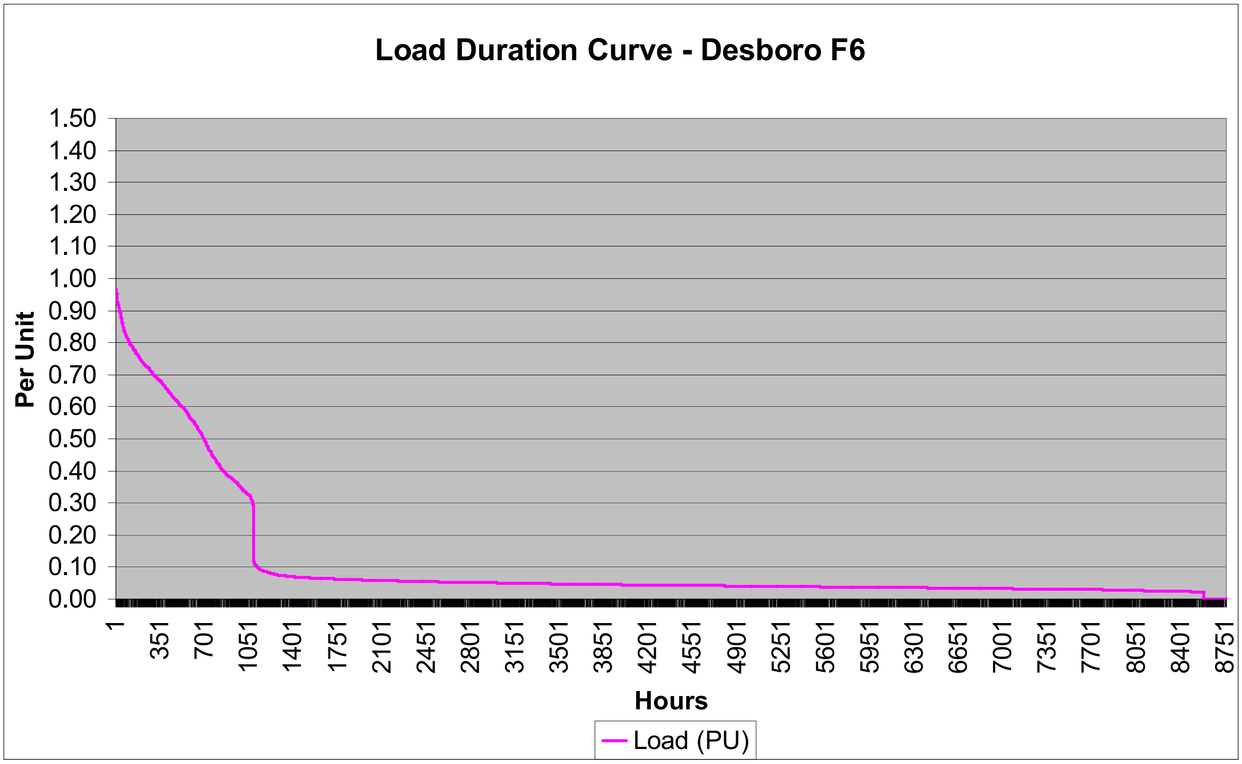
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Desboro F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Desboro F6
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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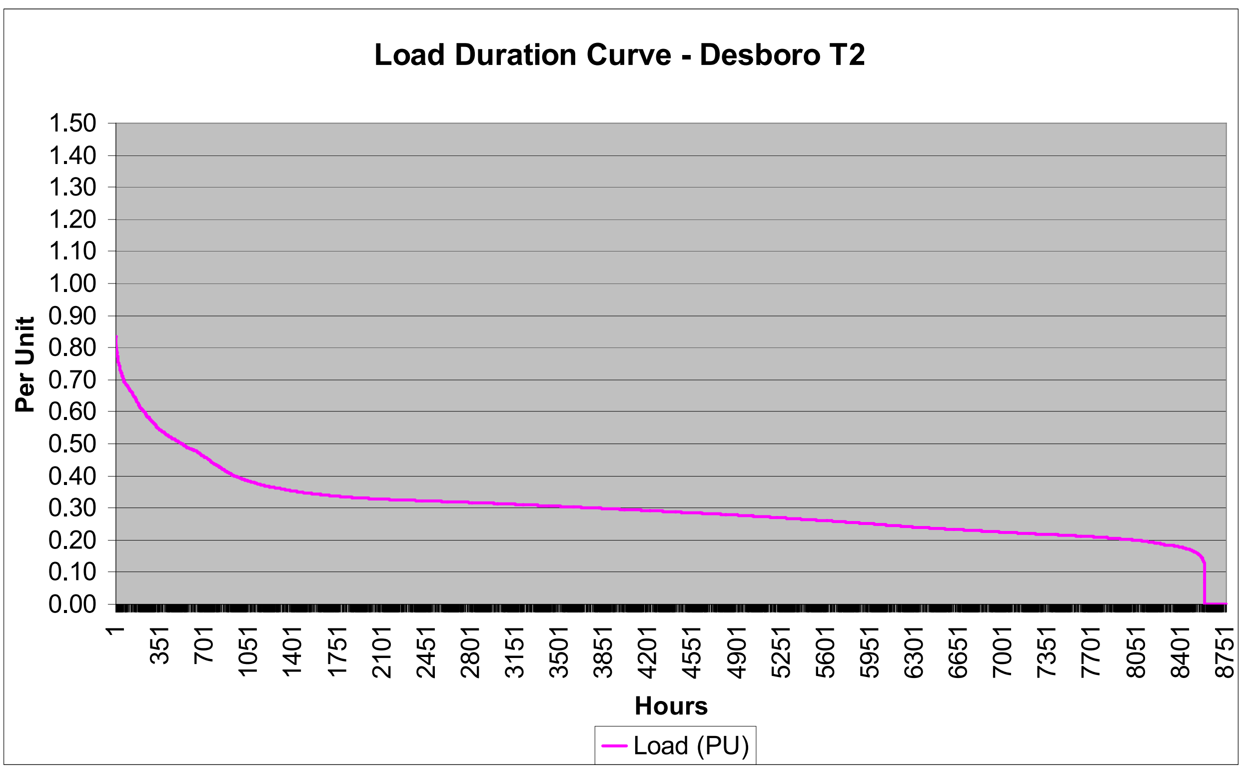
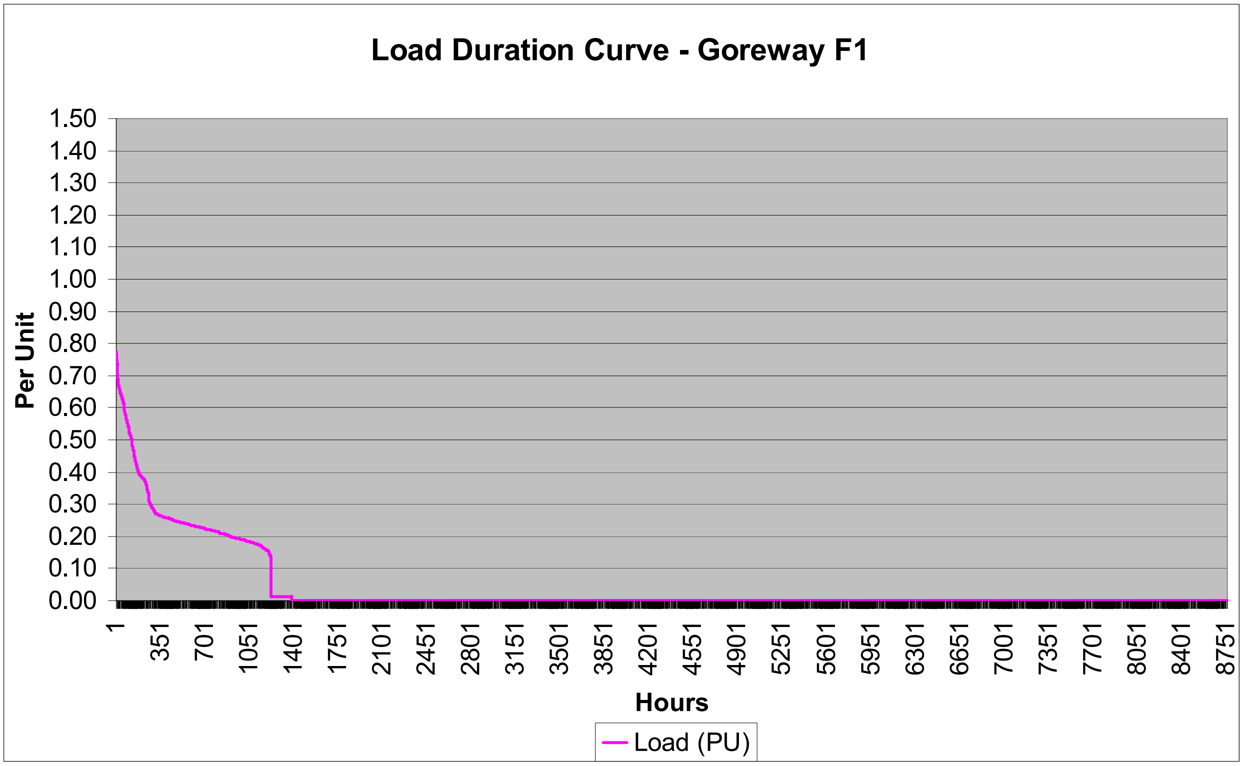
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Desboro T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Goreway MS


Load Duration Curve - Goreway F1
Per Unit
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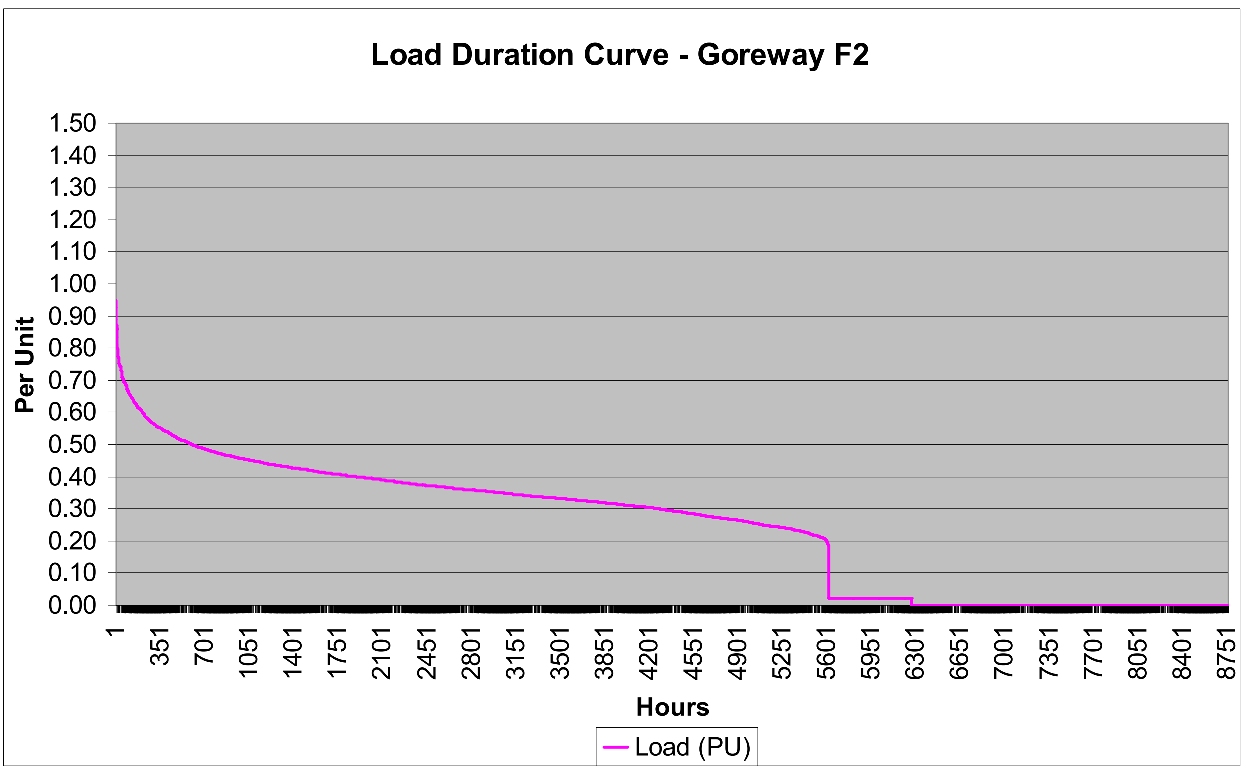
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Goreway F2
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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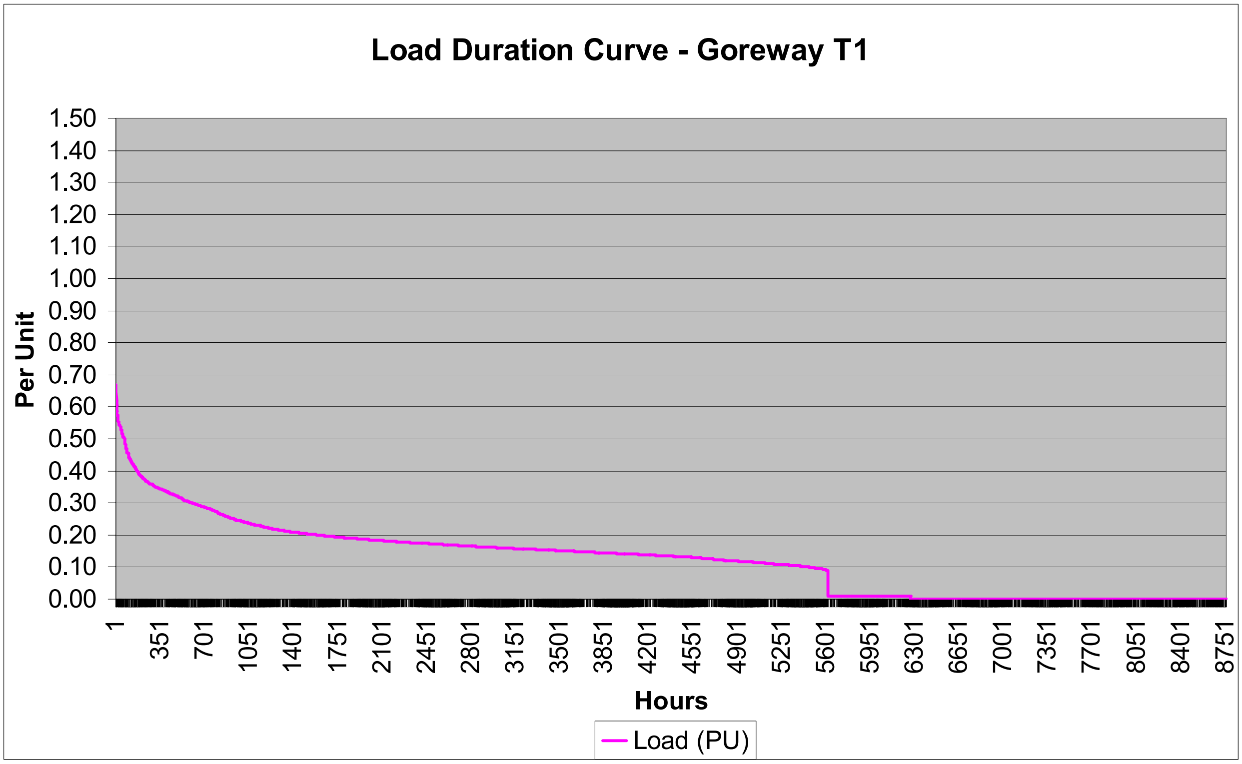
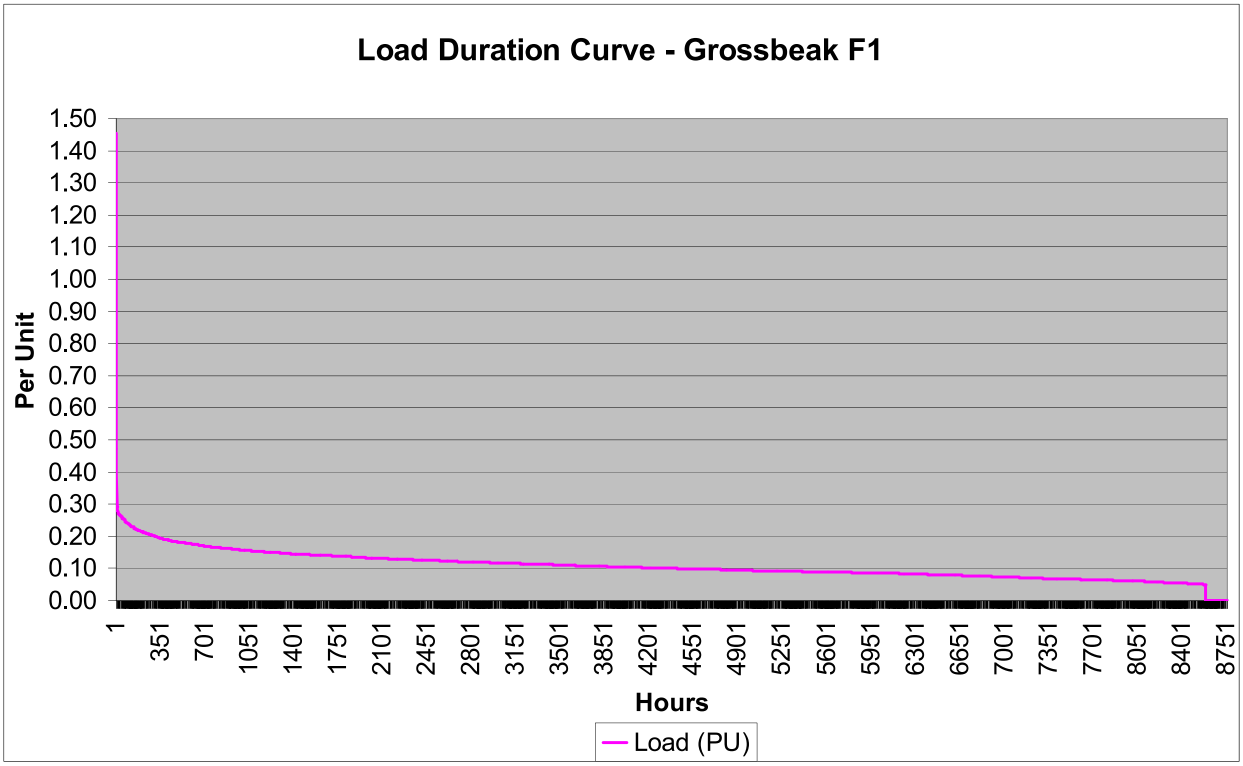
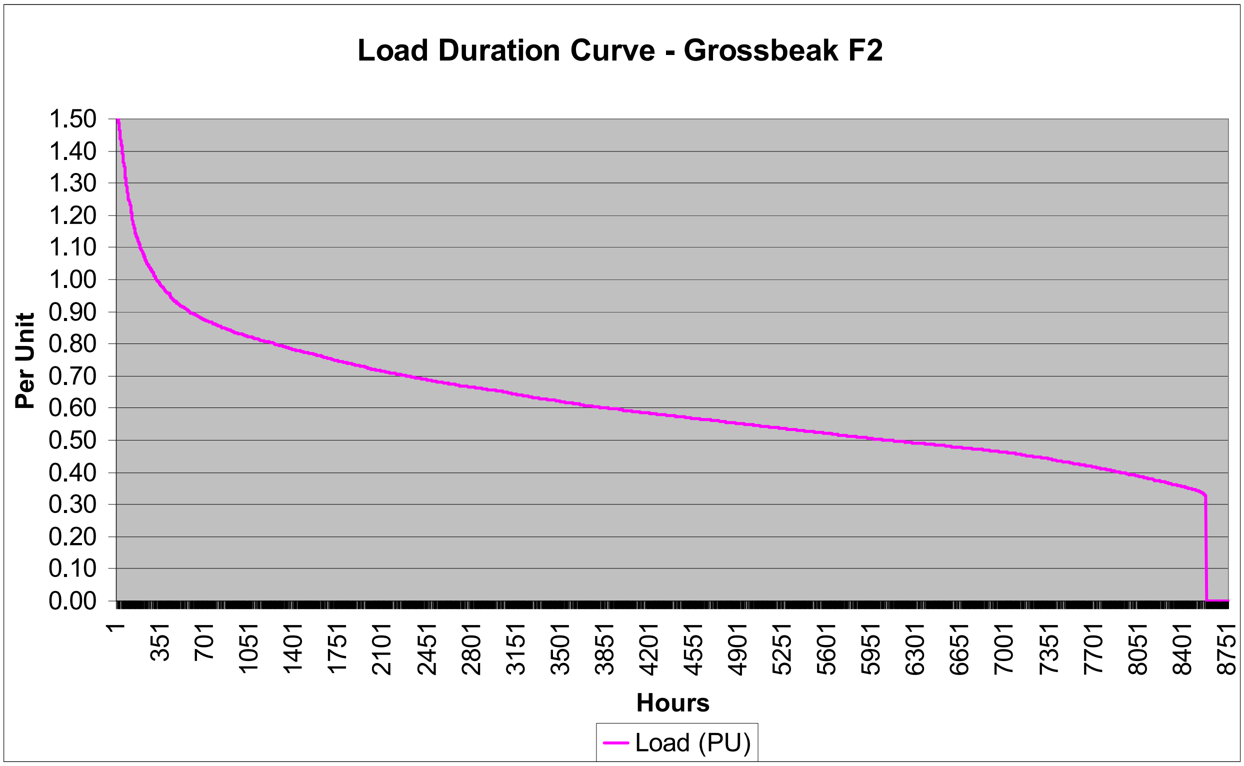
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

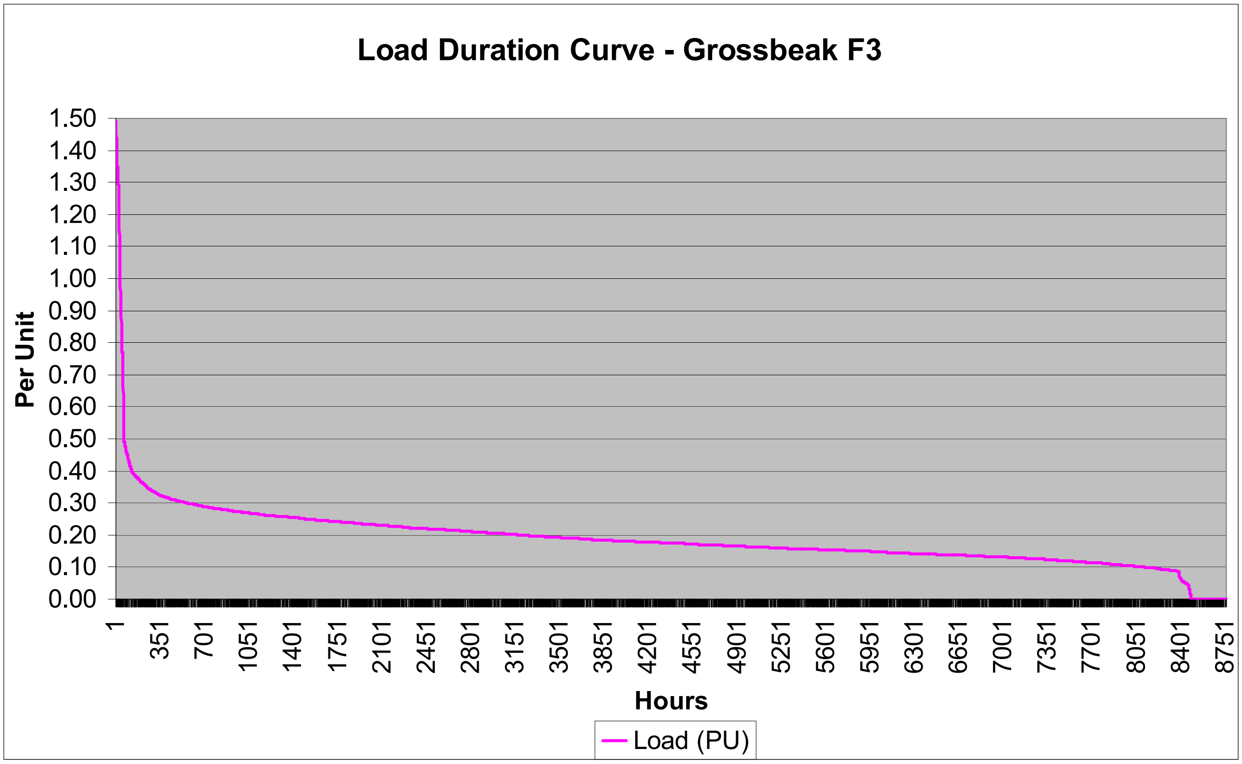


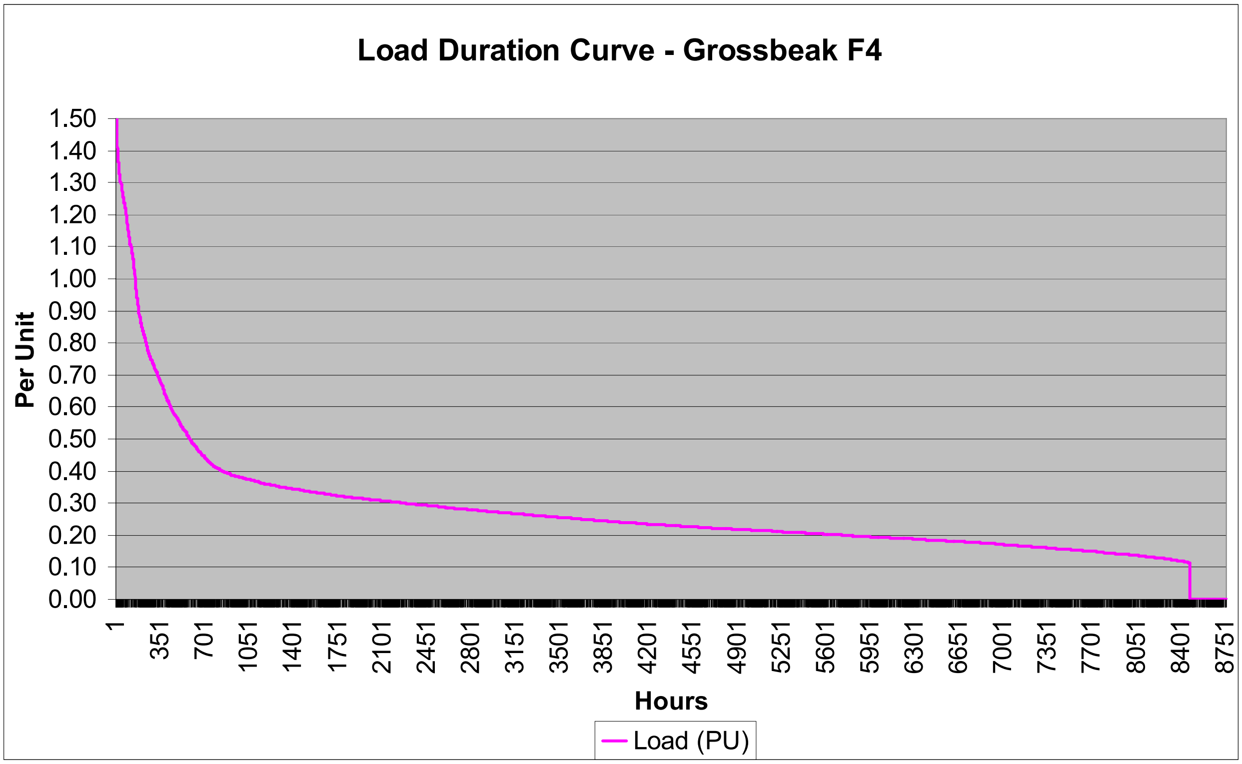
Load Duration Curve - Goreway T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

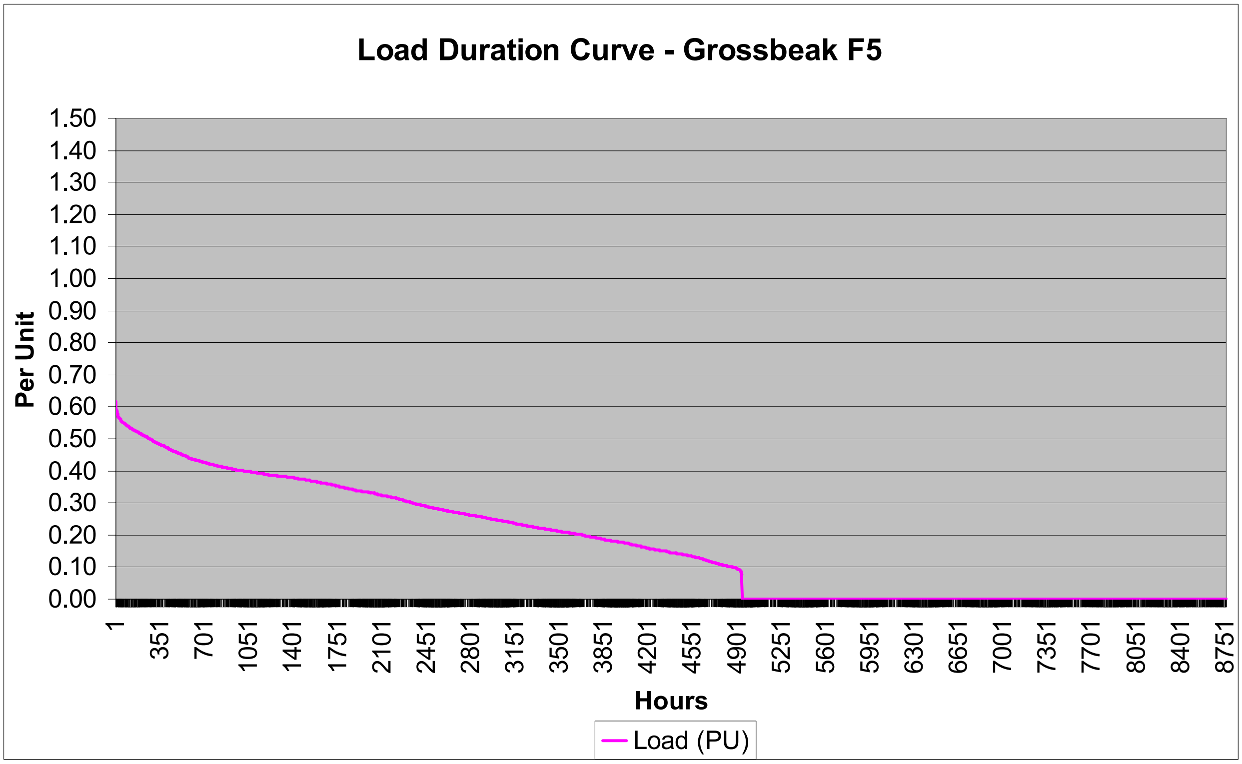
Grossbeak MS

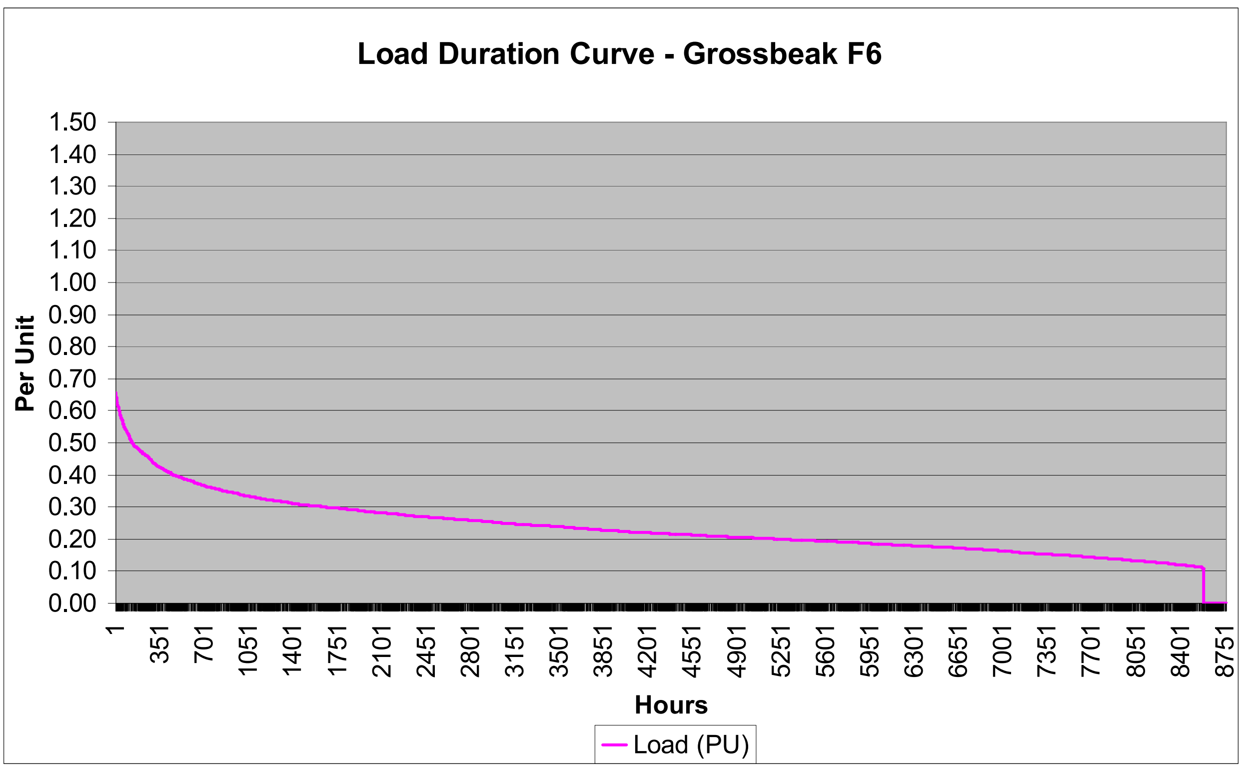


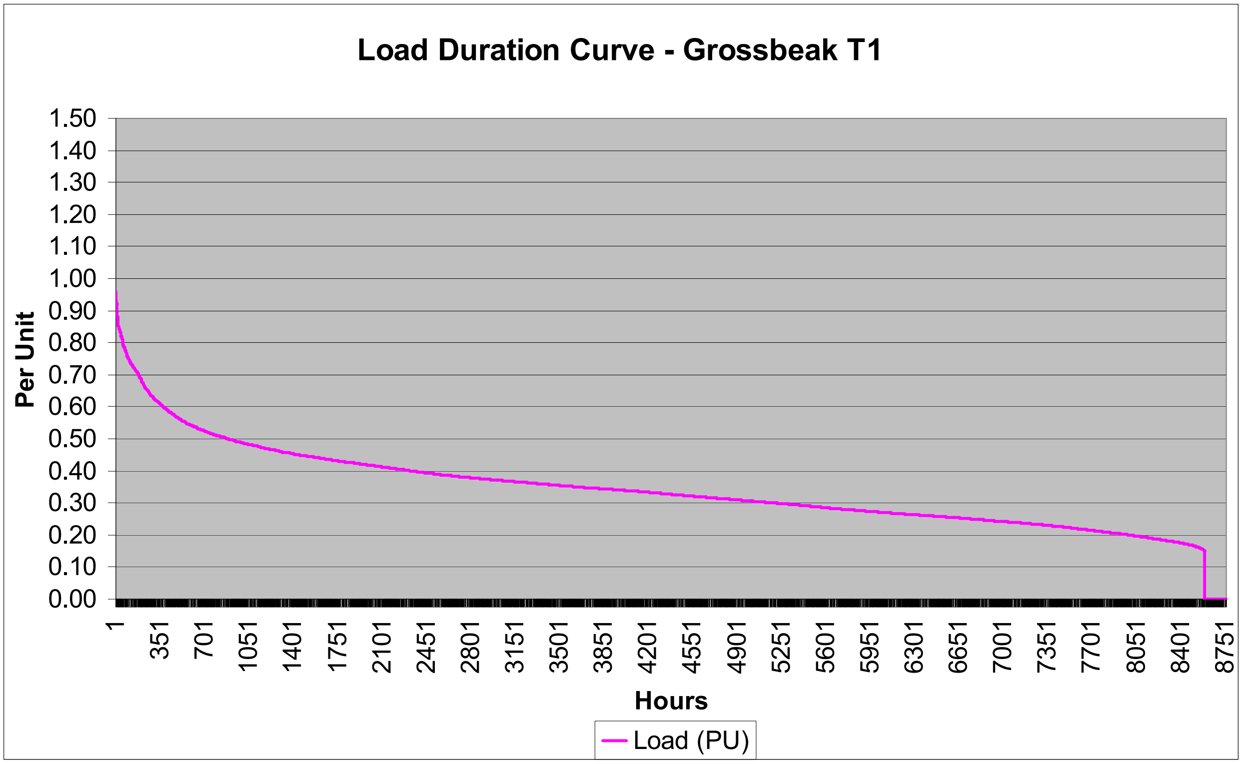



Load Duration Curve - Grossbeak F3
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Grossbeak F4
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

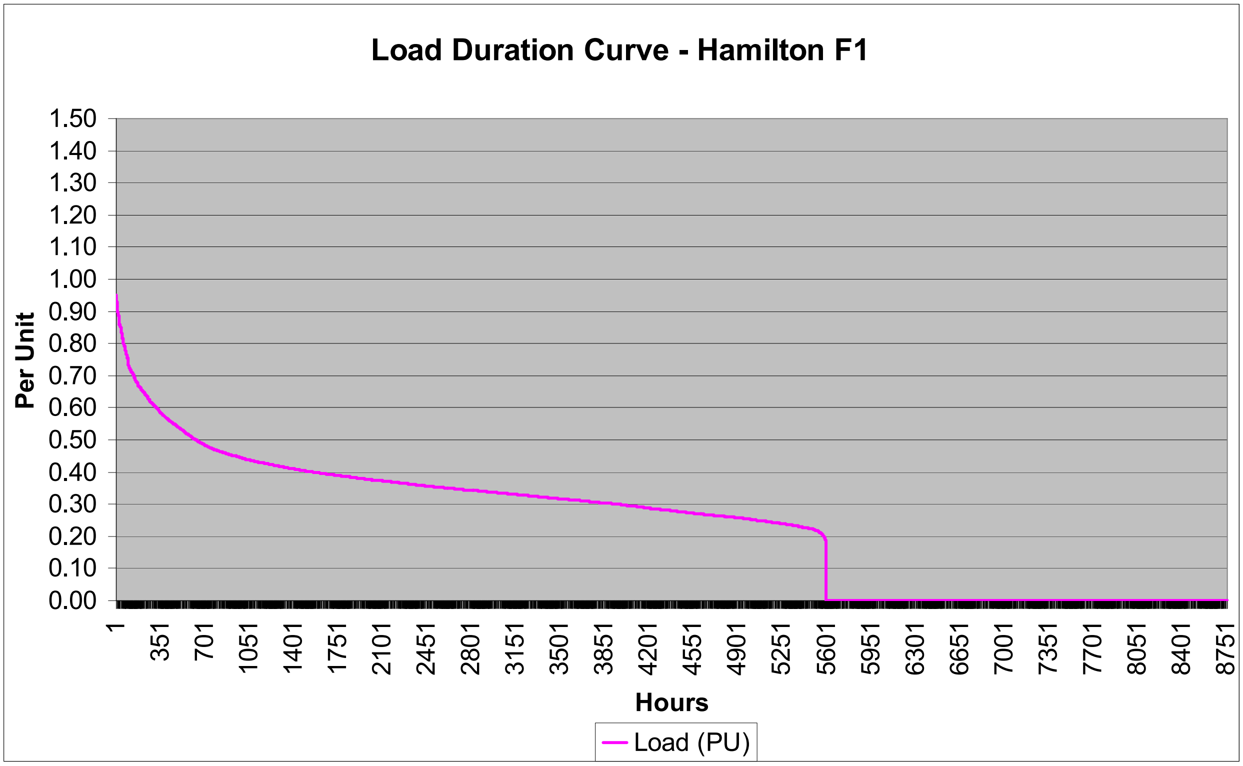

Load Duration Curve - Grossbeak F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Grossbeak F6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Grossbeak T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Hamilton MS


Load Duration Curve - Hamilton F1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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6301
6651
7001
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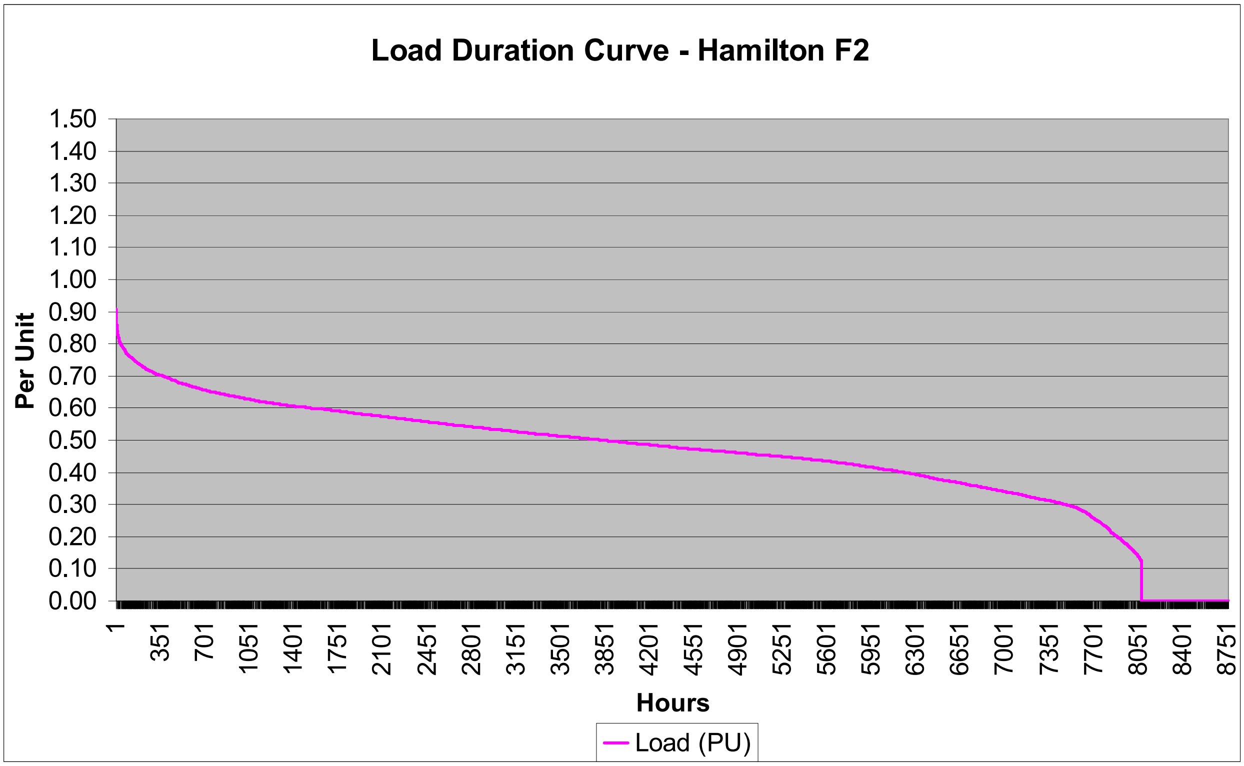
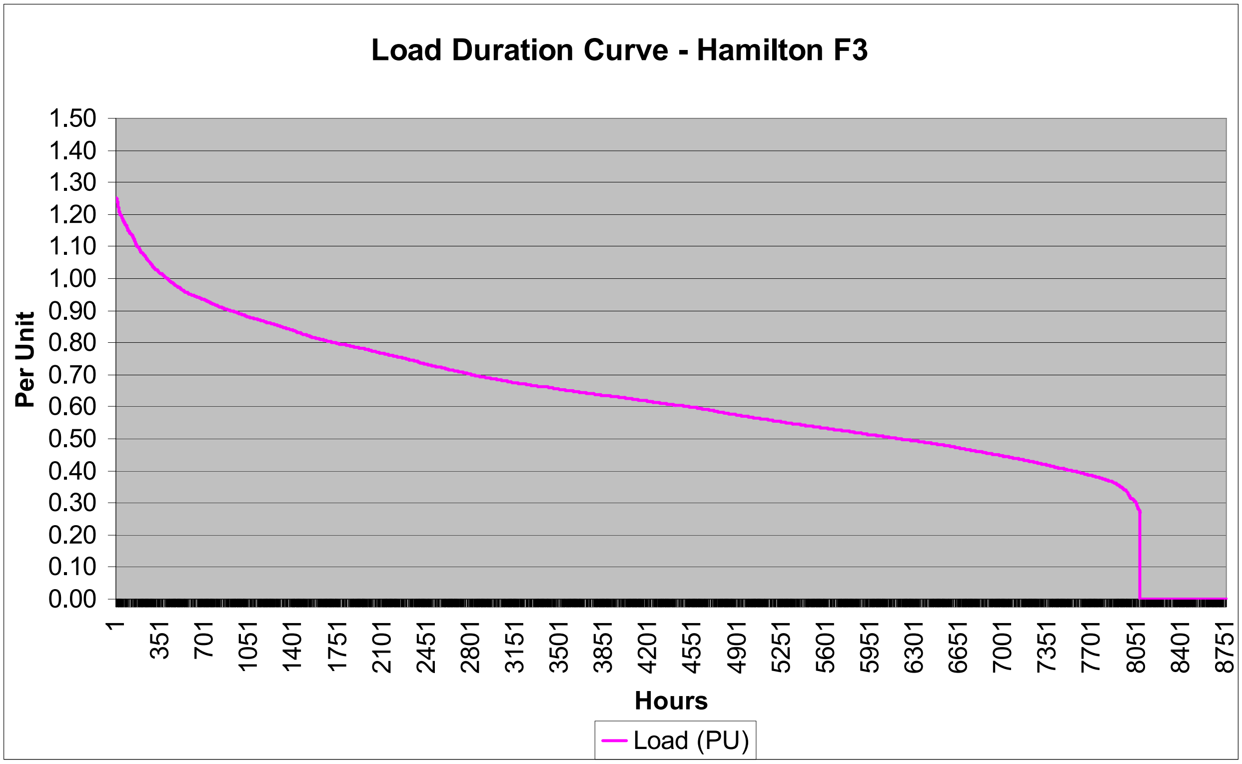
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Hamilton F2
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Hamilton F3
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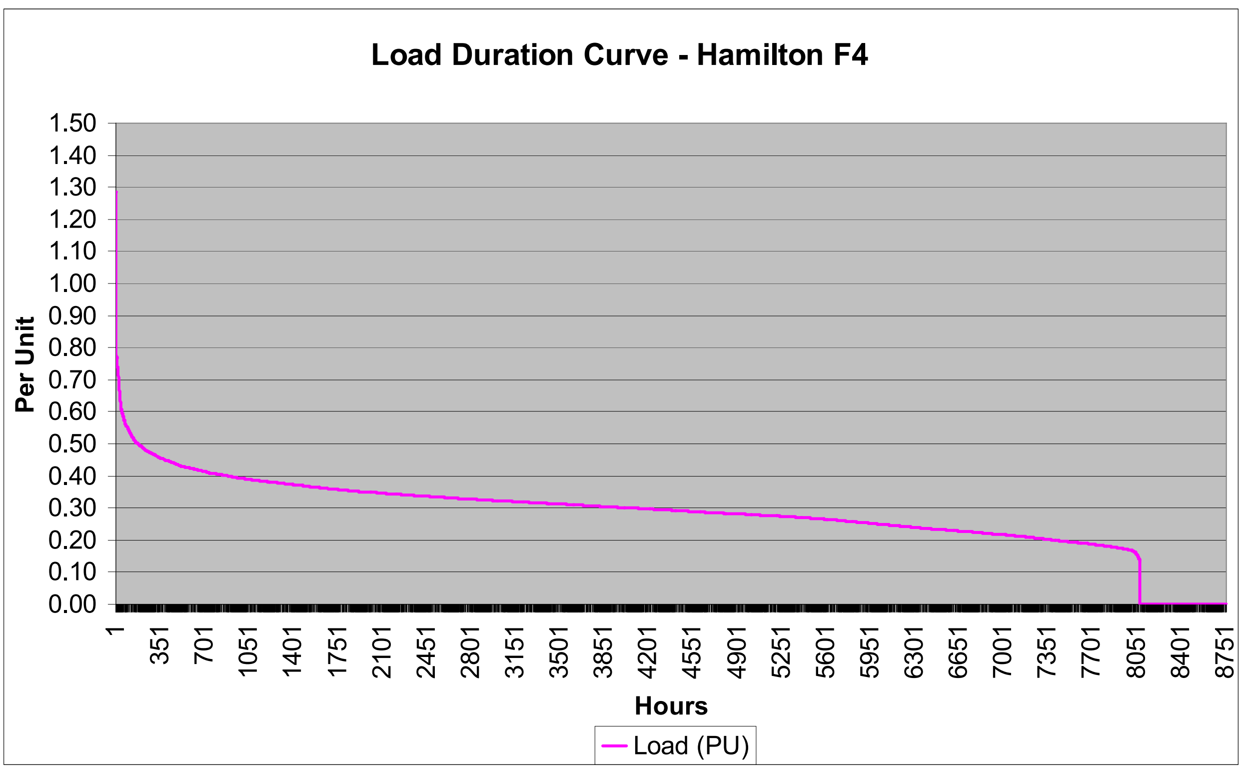
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Hamilton F4
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1.40
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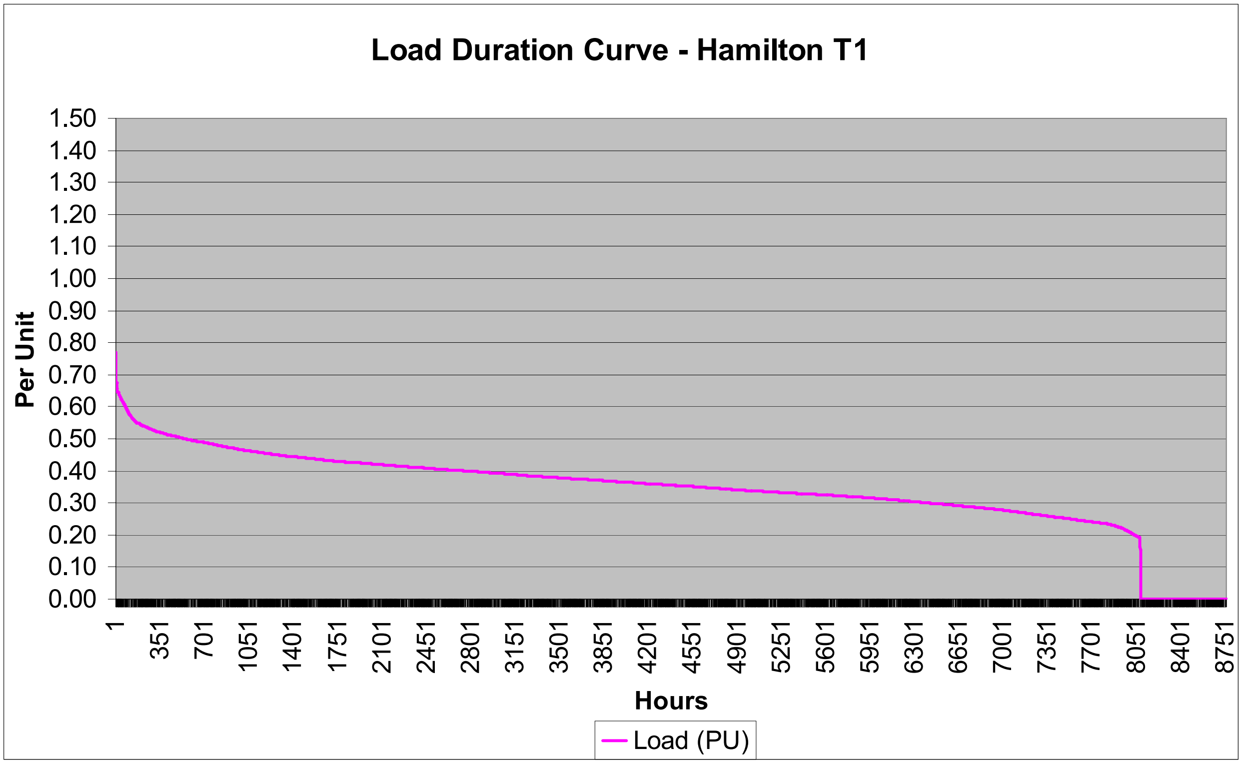
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Hamilton T1
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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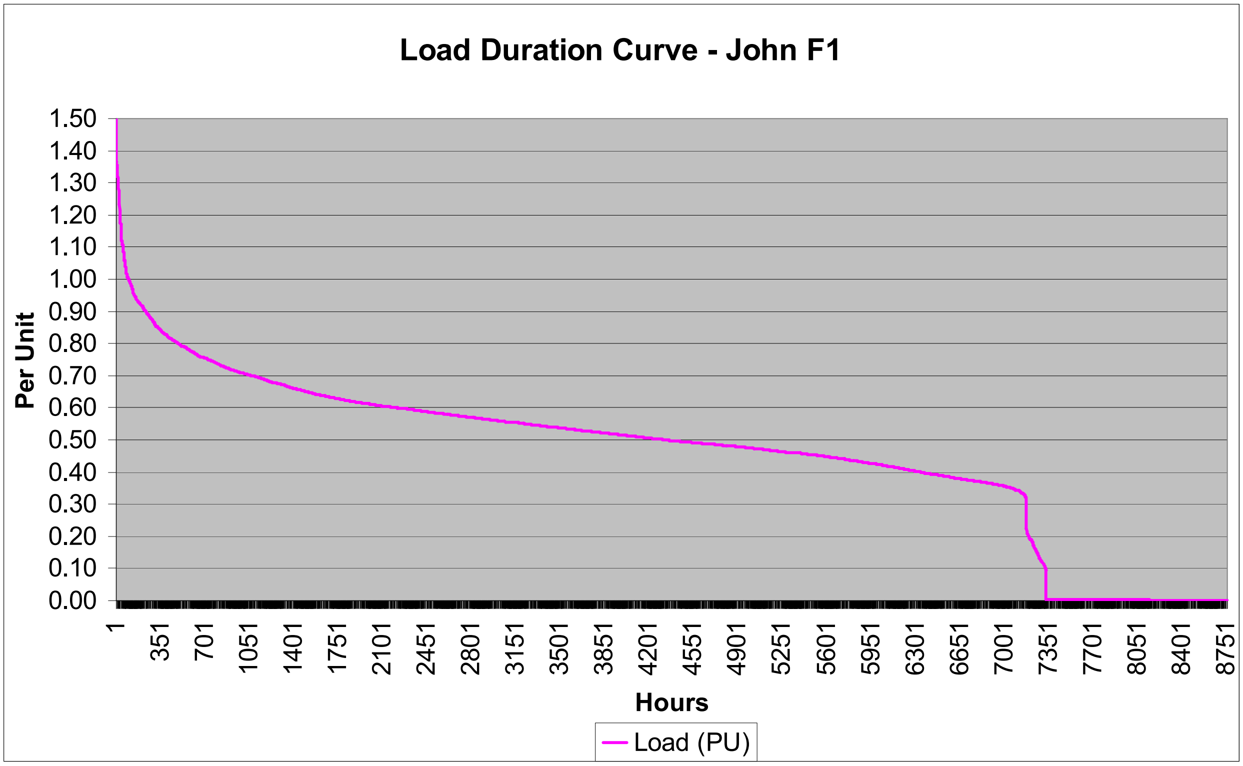
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

John MS



Load Duration Curve - John F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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5951
6301
6651
7001
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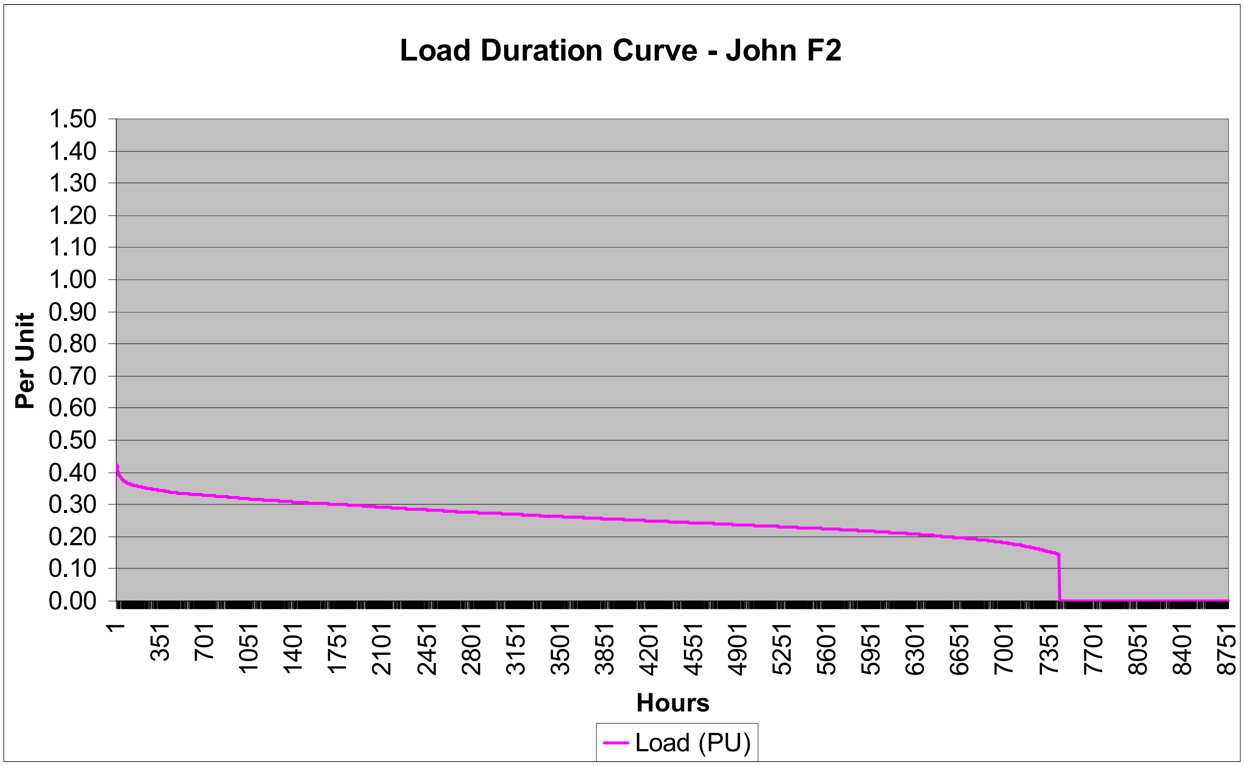
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - John F2
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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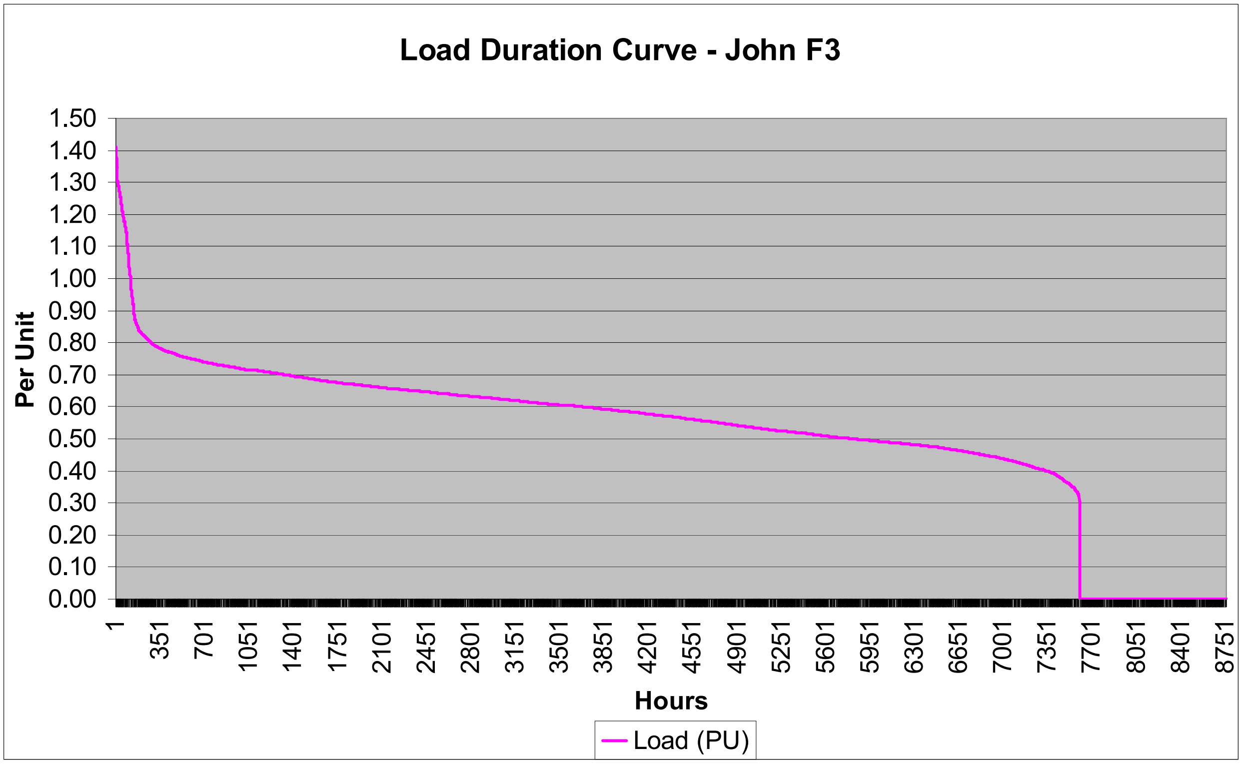
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - John F3
Per Unit
Hours
Load (PU)
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
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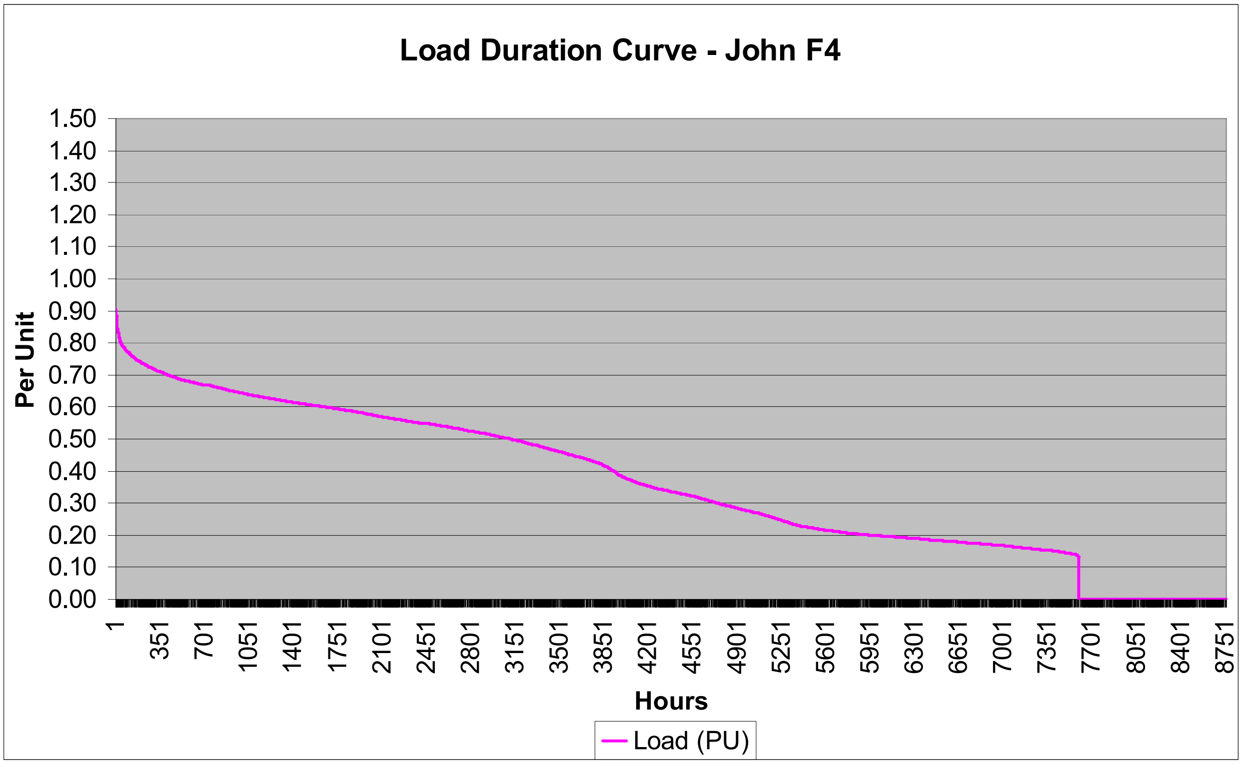
8051
8401
8751


Load Duration Curve - John F4
Per Unit
Hours
Load (PU)
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
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5251
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7001
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8051
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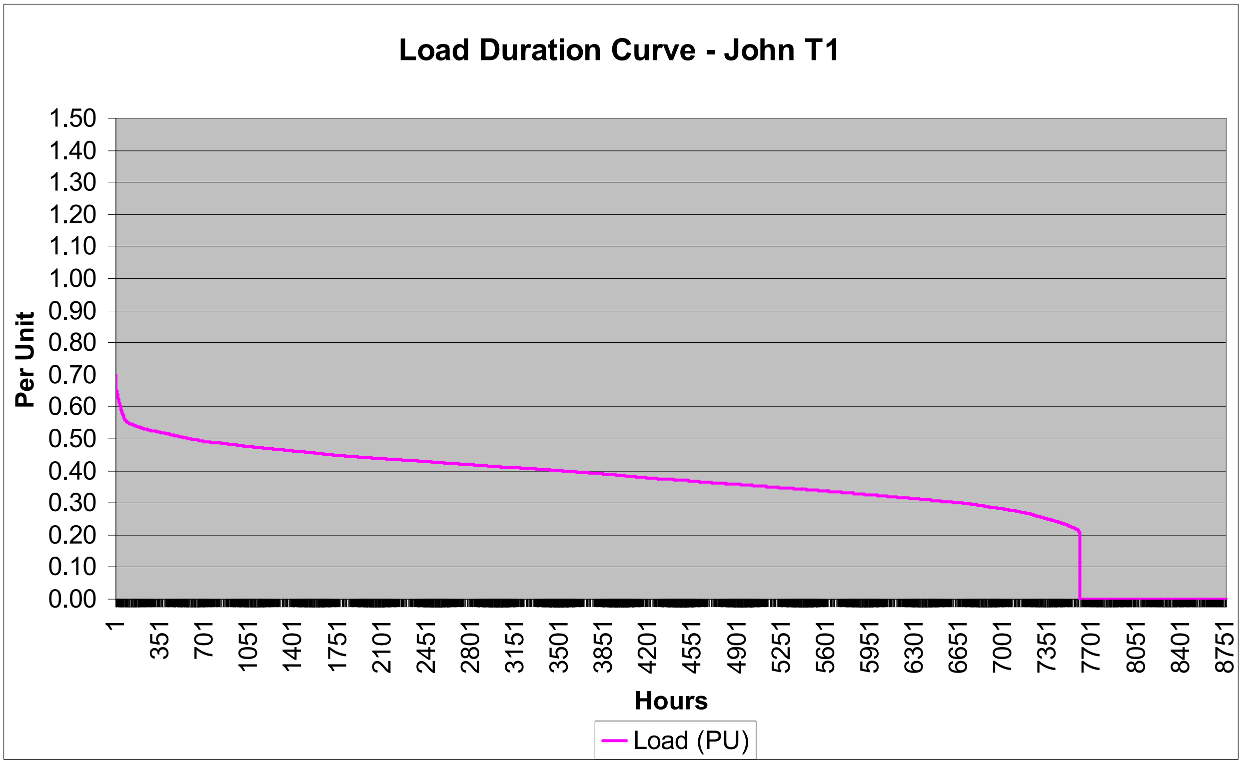

Load Duration Curve - John T1
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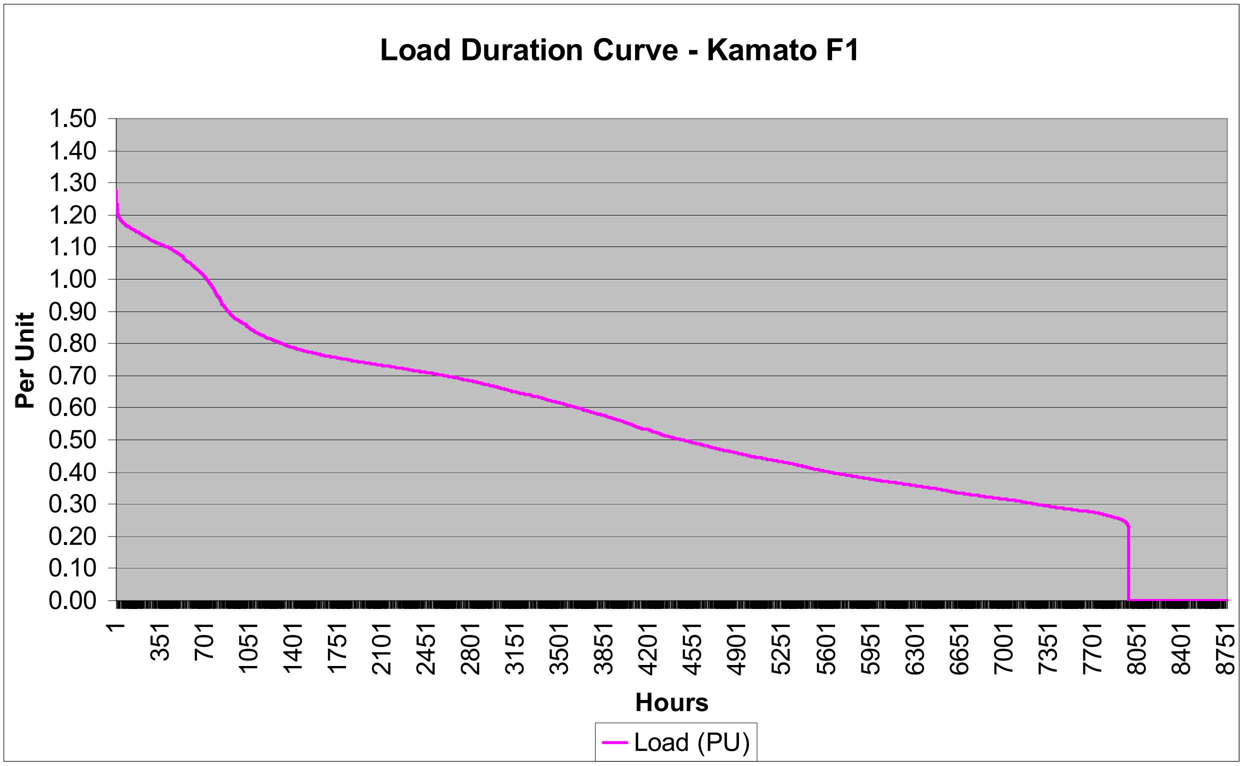
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Kamato MS


Load Duration Curve - Kamato F1
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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4201
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6651
7001
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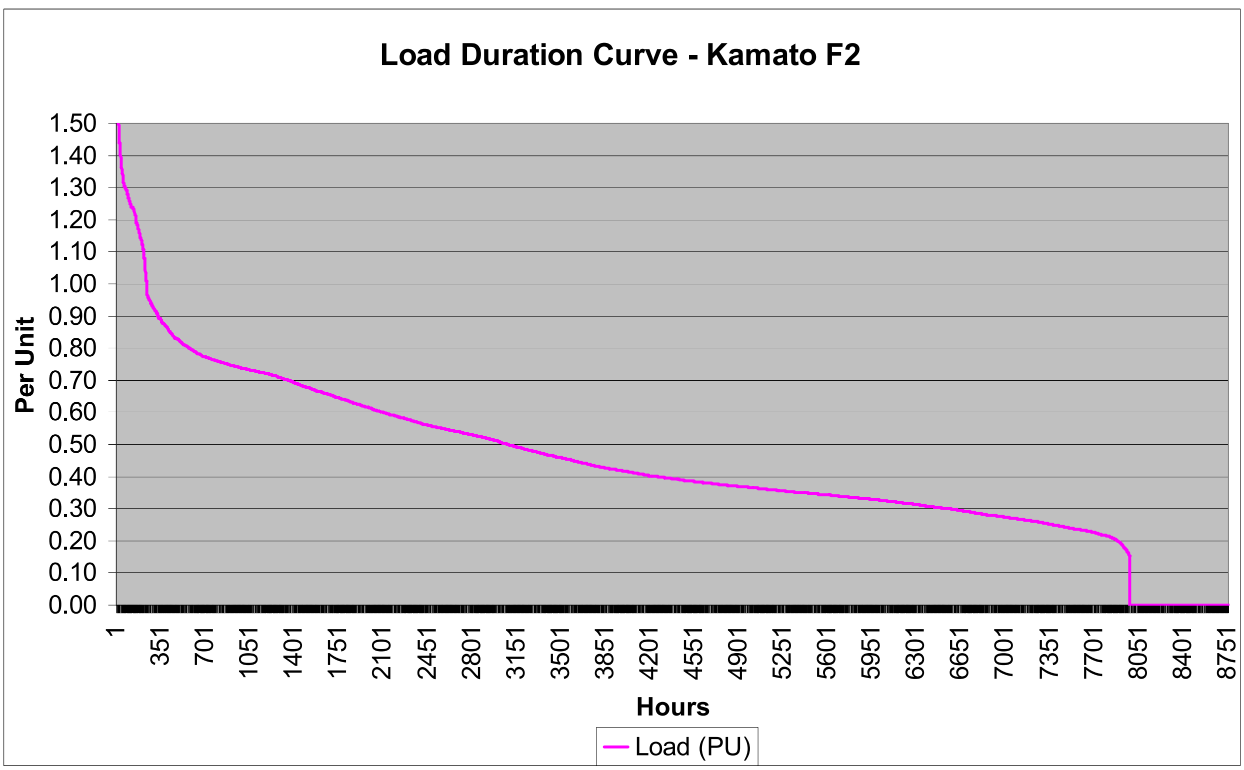
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Kamato F2
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3501
3851
4201
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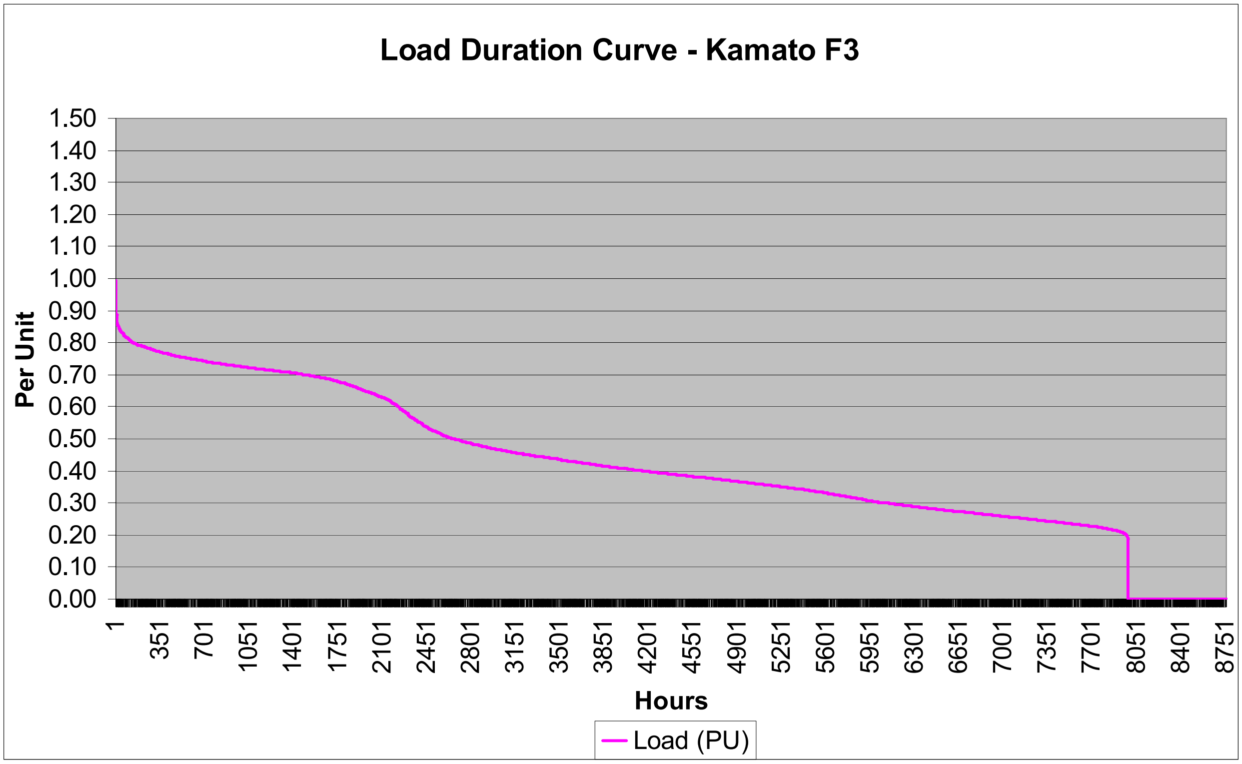
8751
Hours
Load (PU)



Load Duration Curve - Kamato F3
Per Unit
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0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
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4201
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7351
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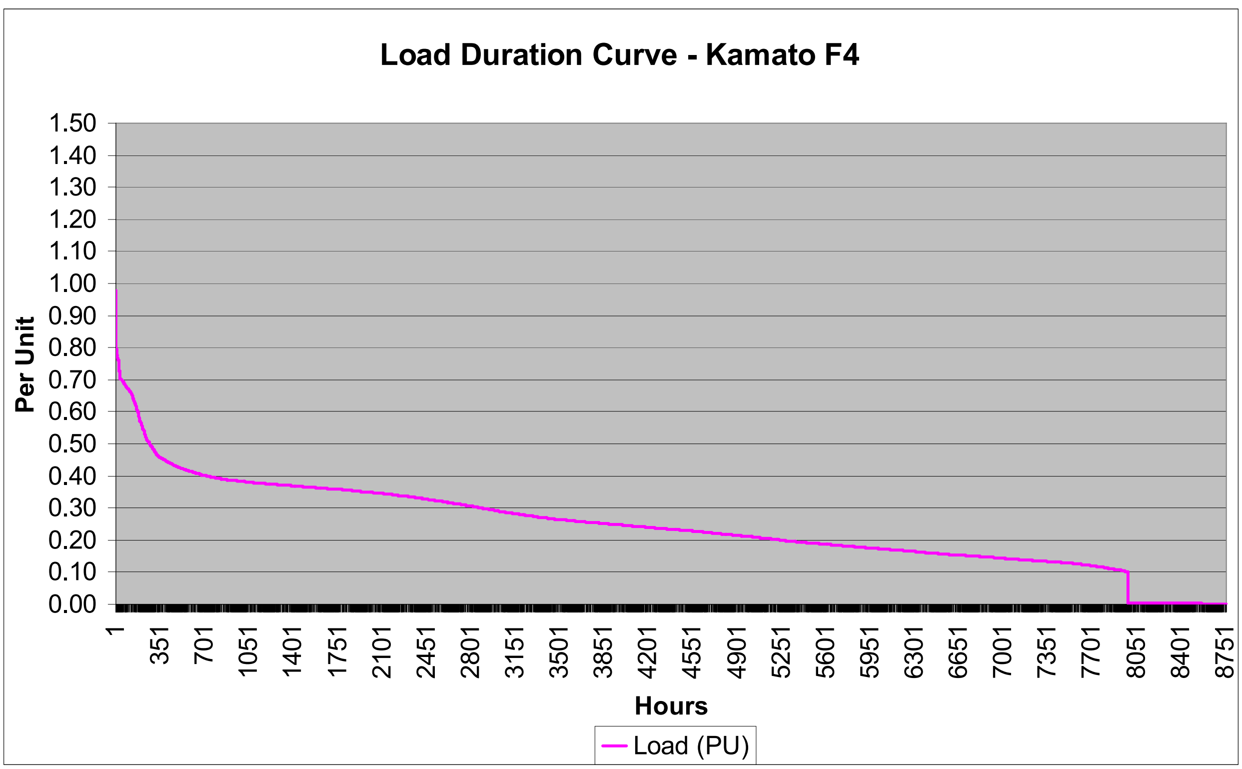
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Kamato F4
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
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4201
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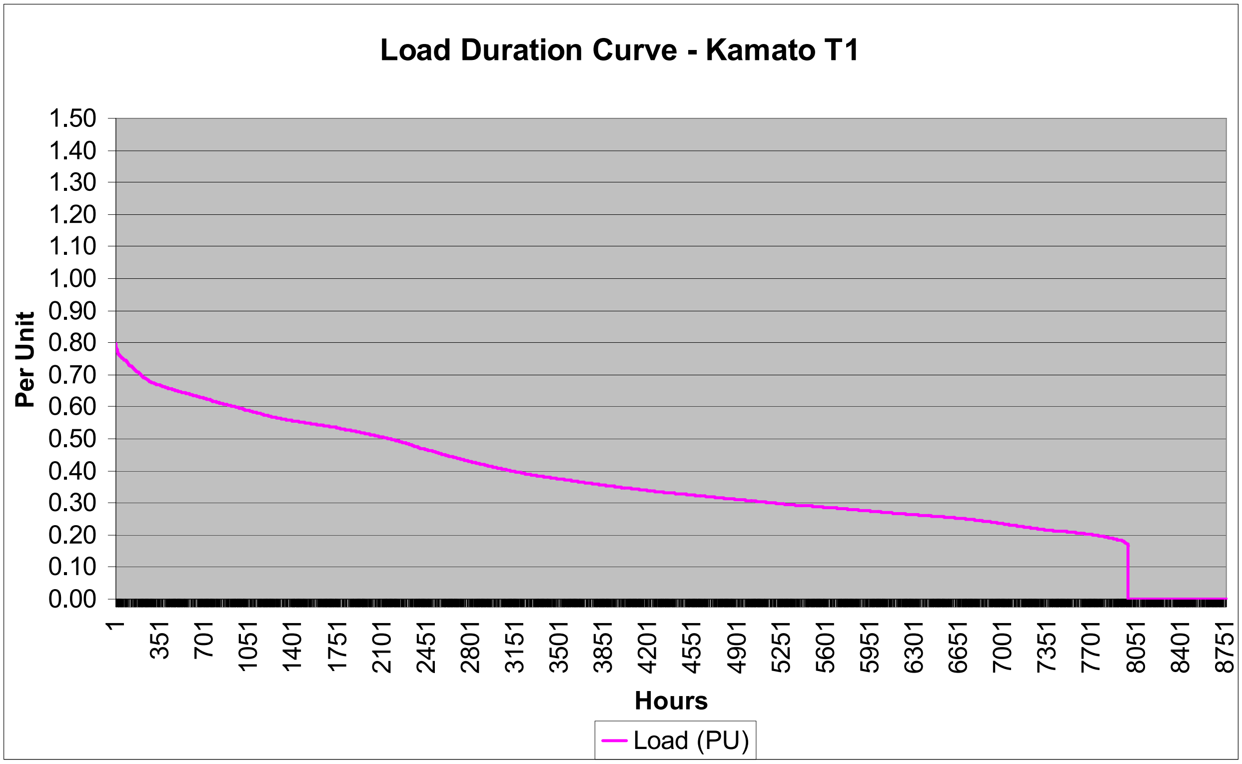
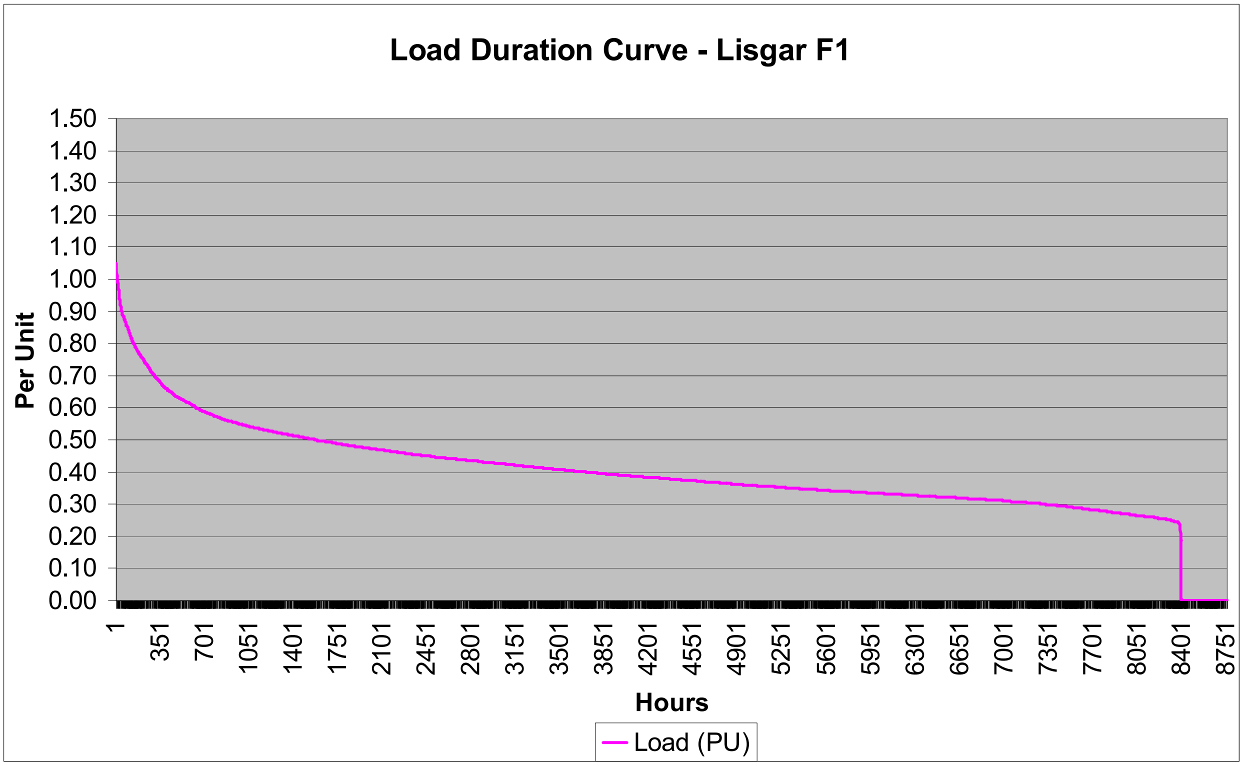
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Kamato T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Lisgar MS


Load Duration Curve - Lisgar F1
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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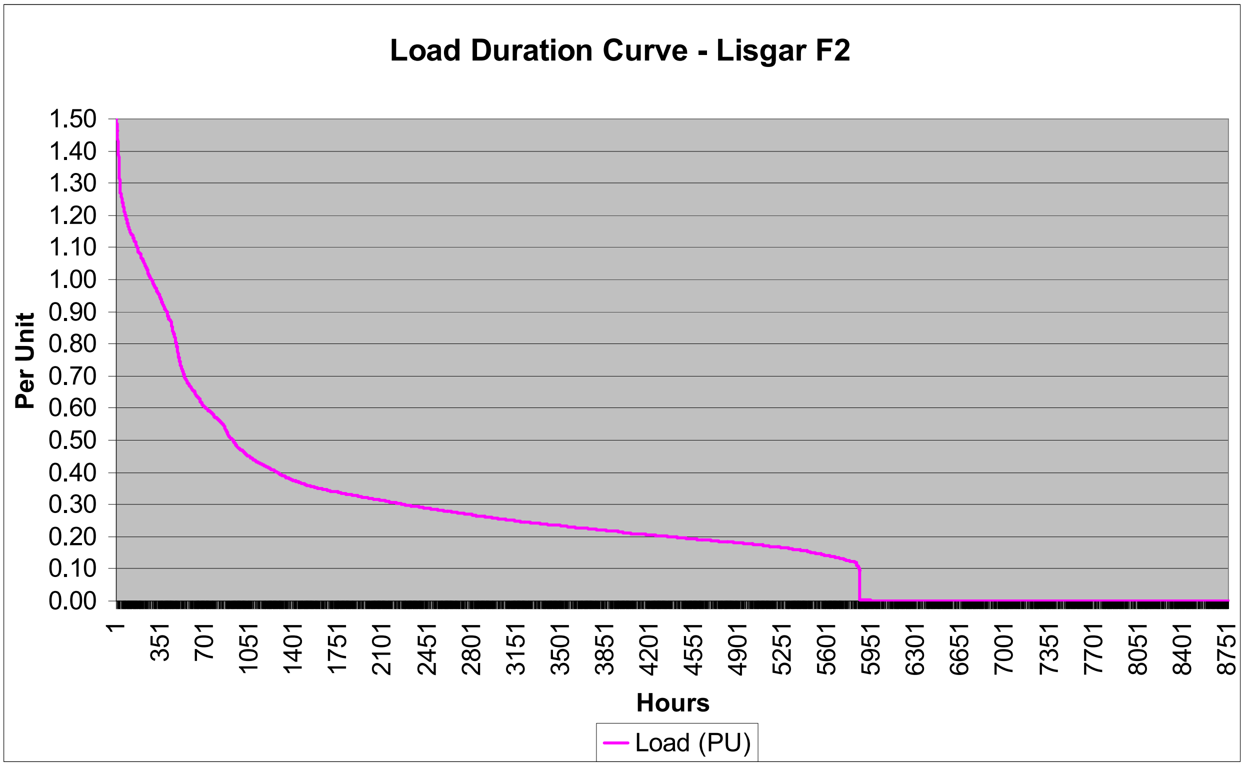
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lisgar F2
Per Unit
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1.40
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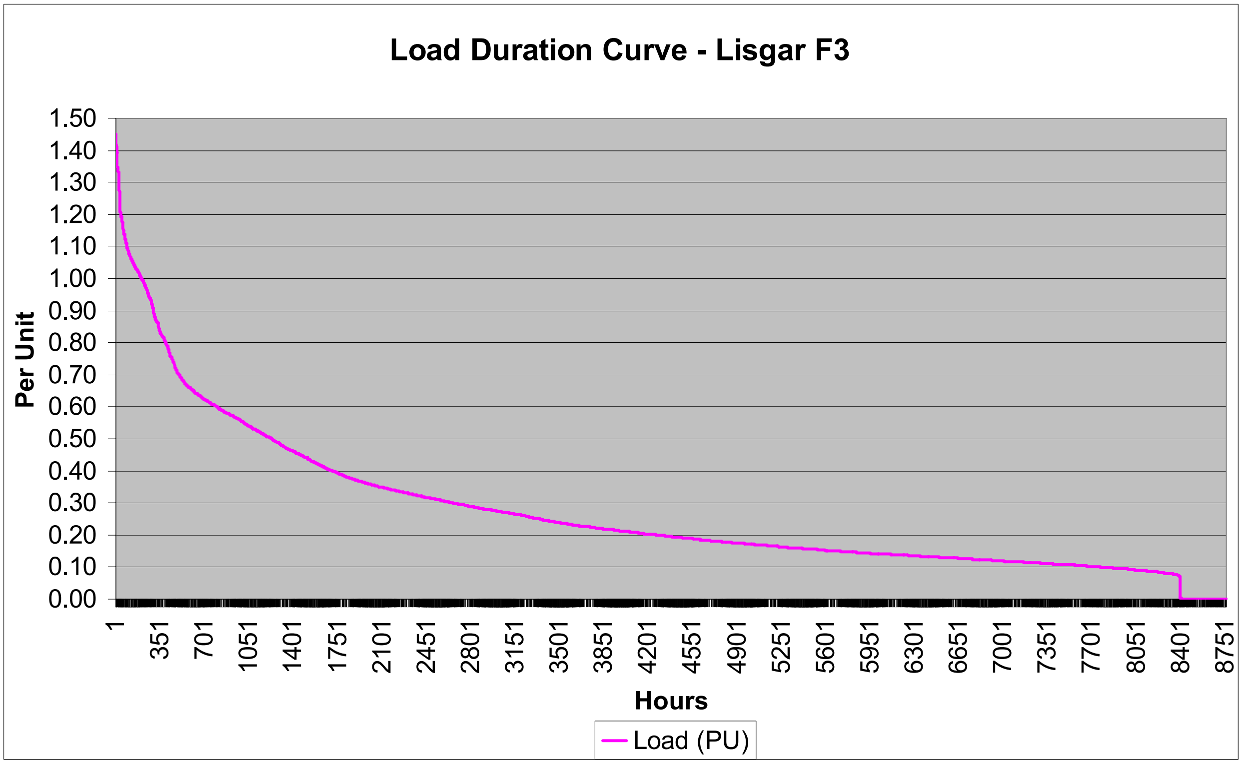
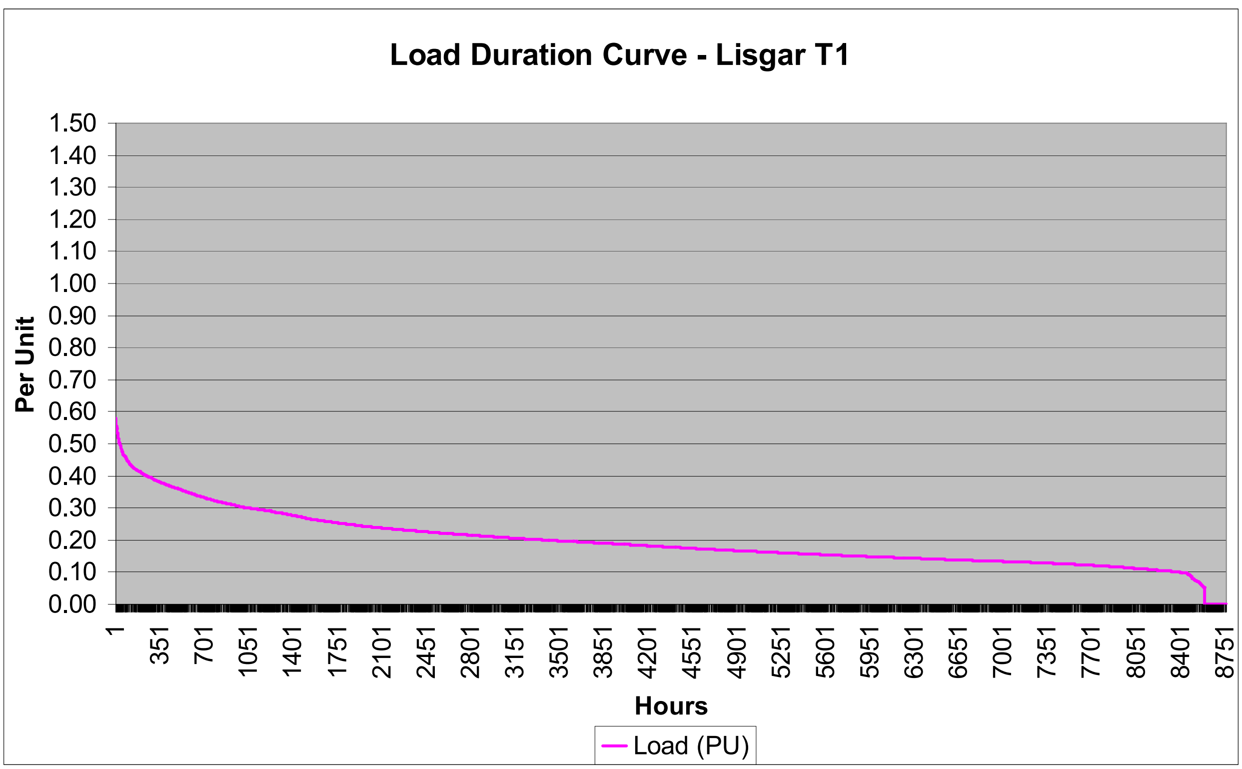
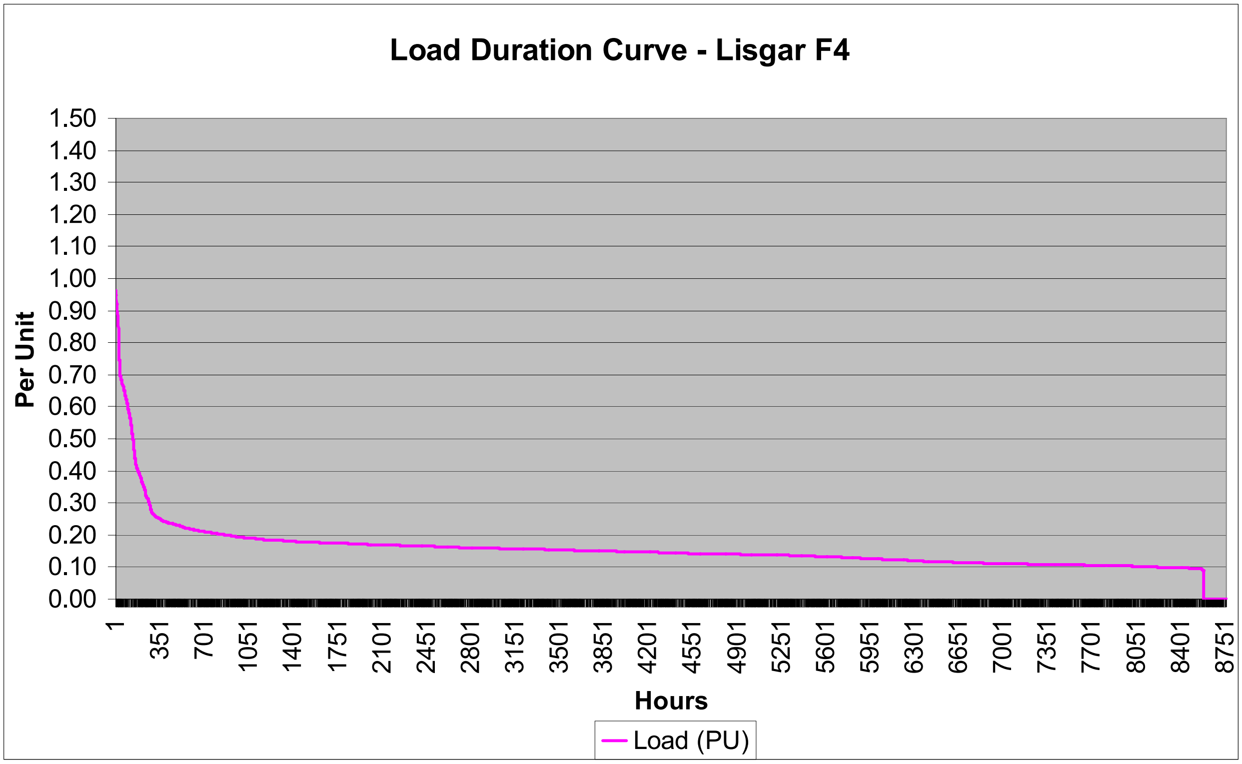
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

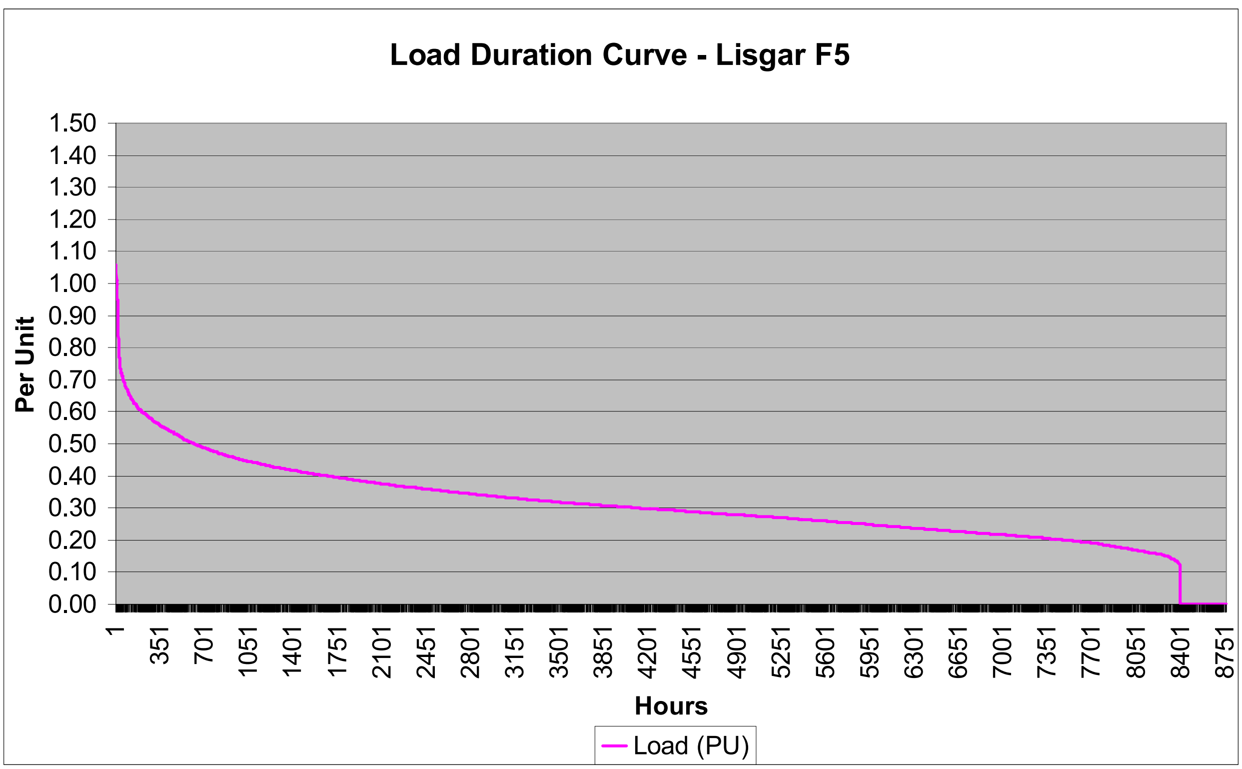


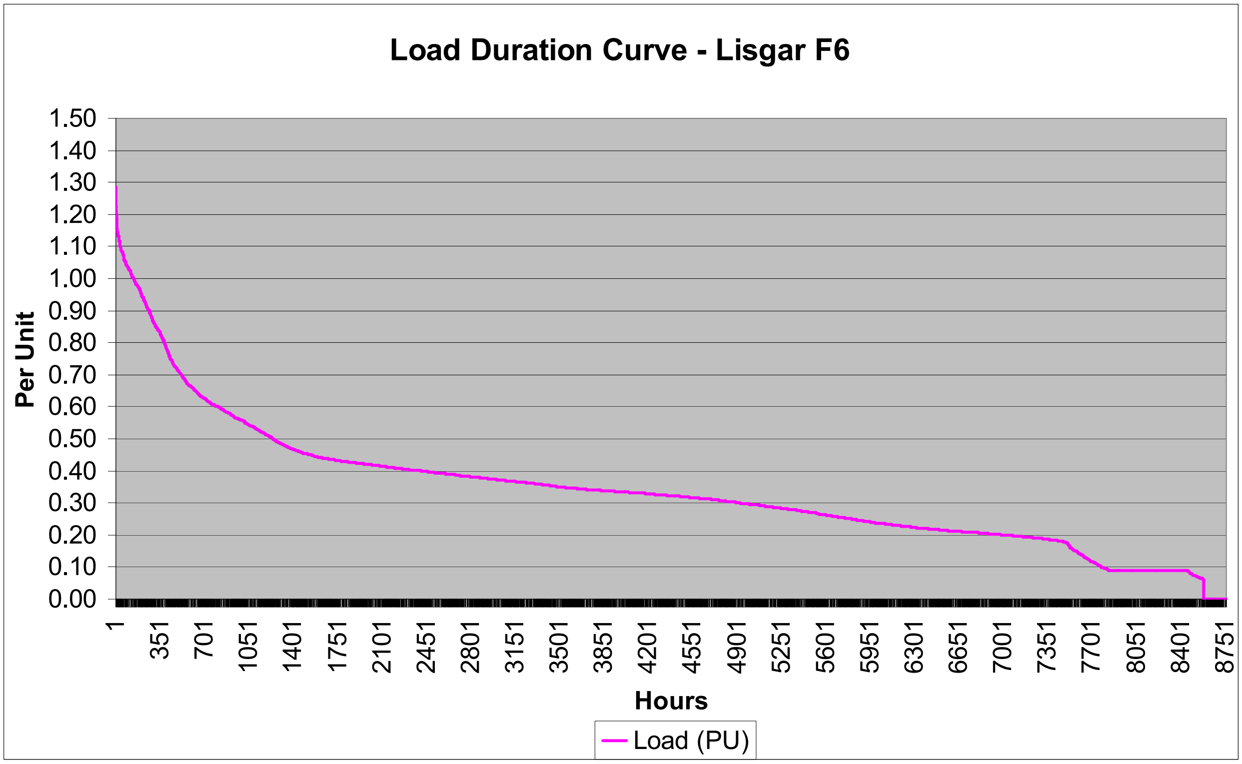
Load Duration Curve - Lisgar F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

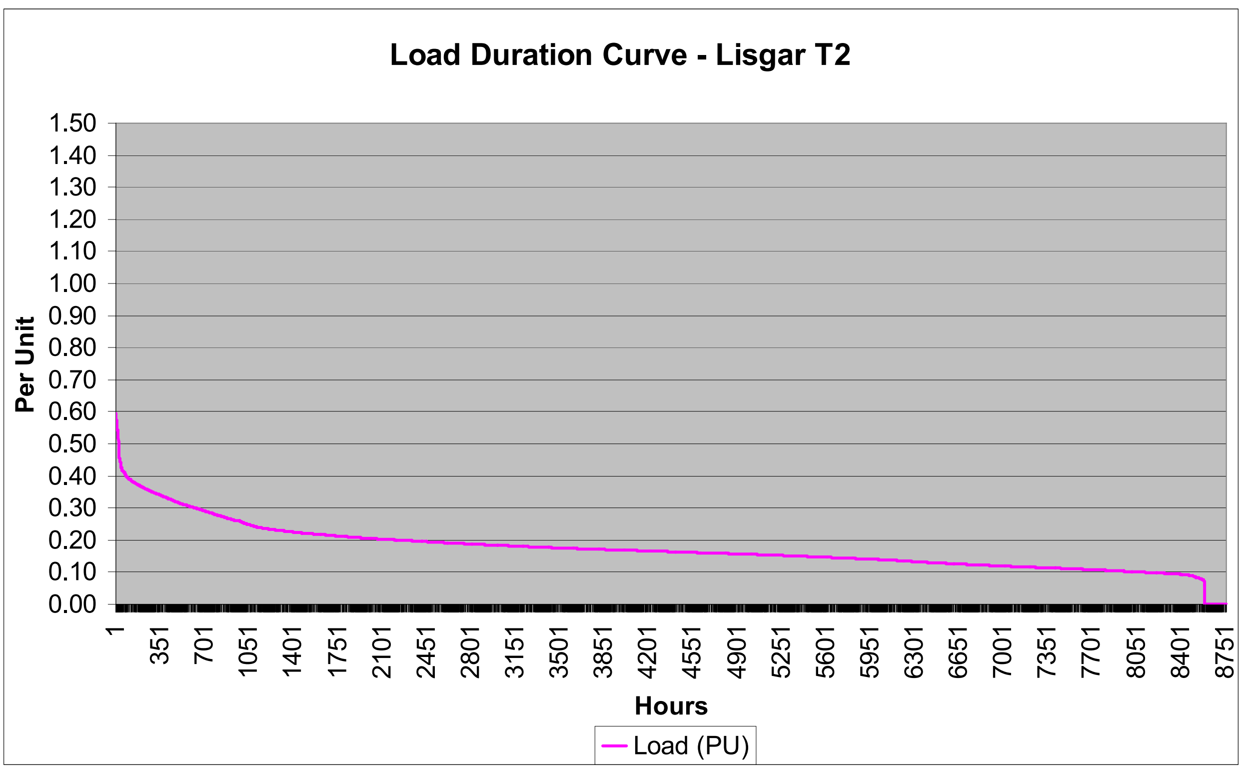


Load Duration Curve - Lisgar T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

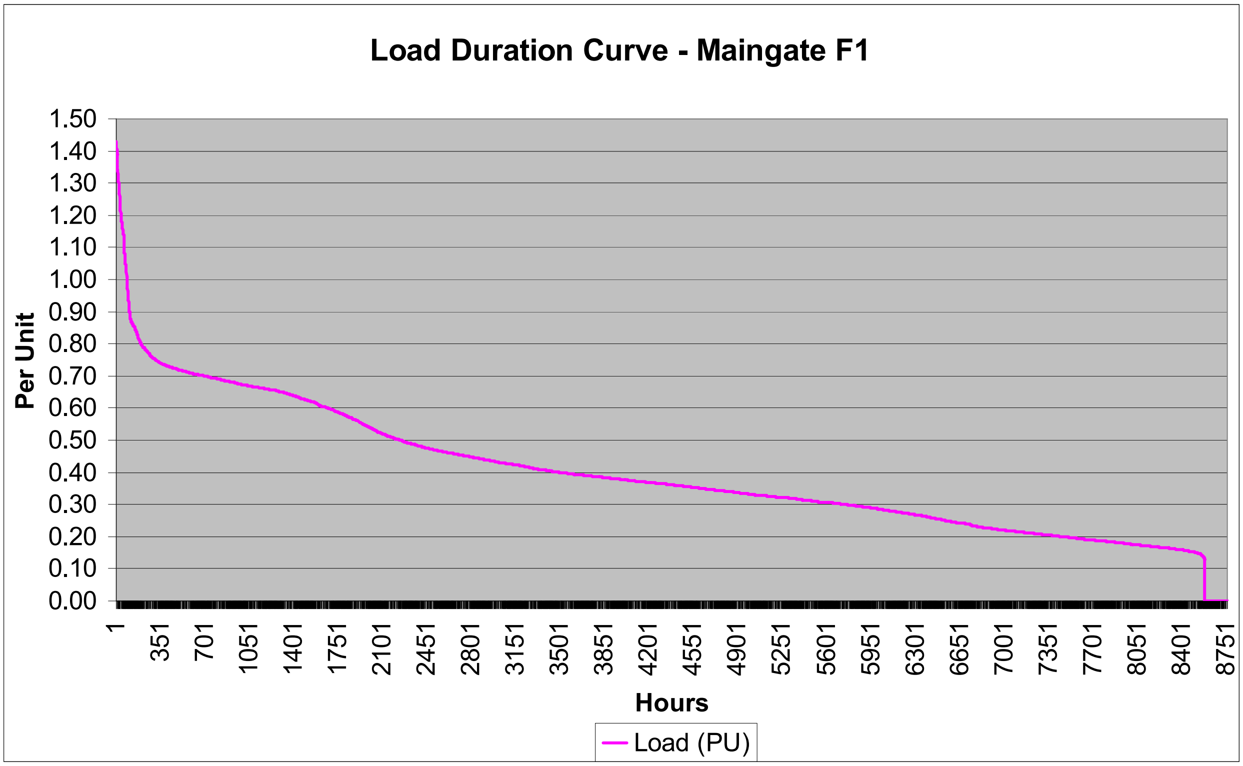

Load Duration Curve - Lisgar F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lisgar F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

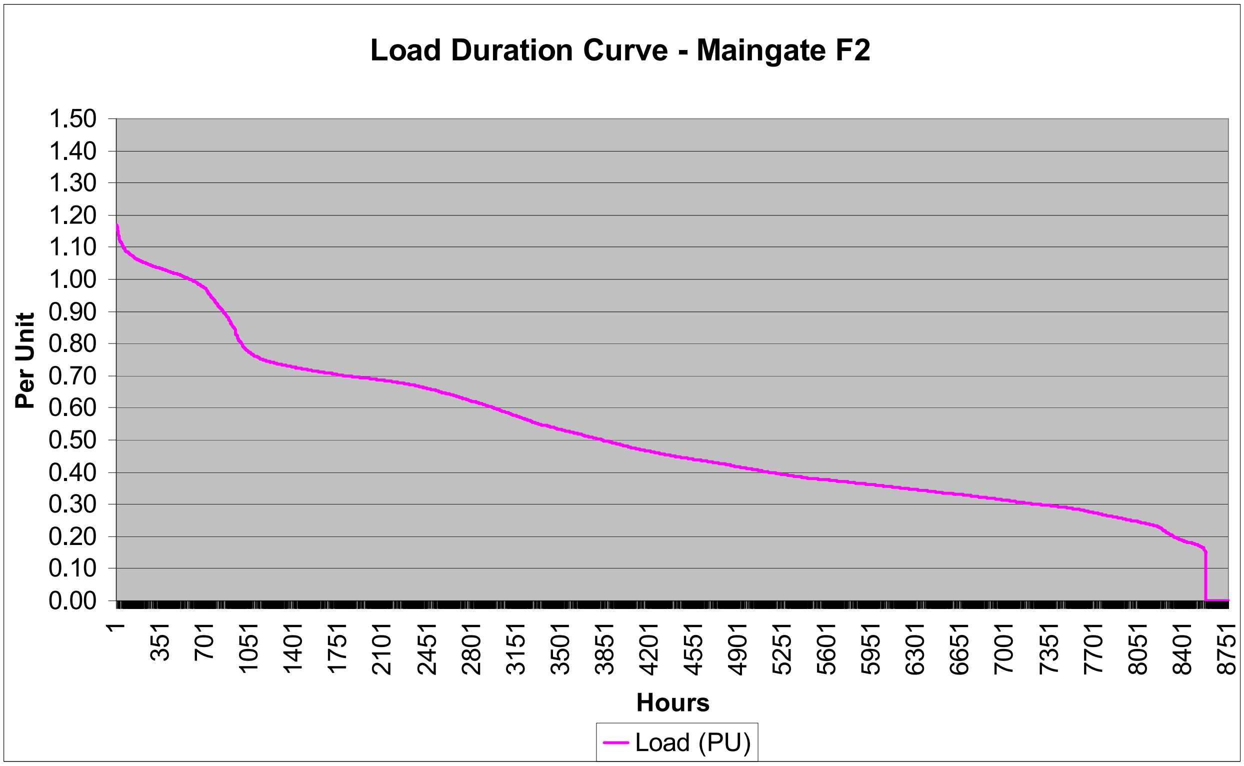

Load Duration Curve - Lisgar F6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Lisgar T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

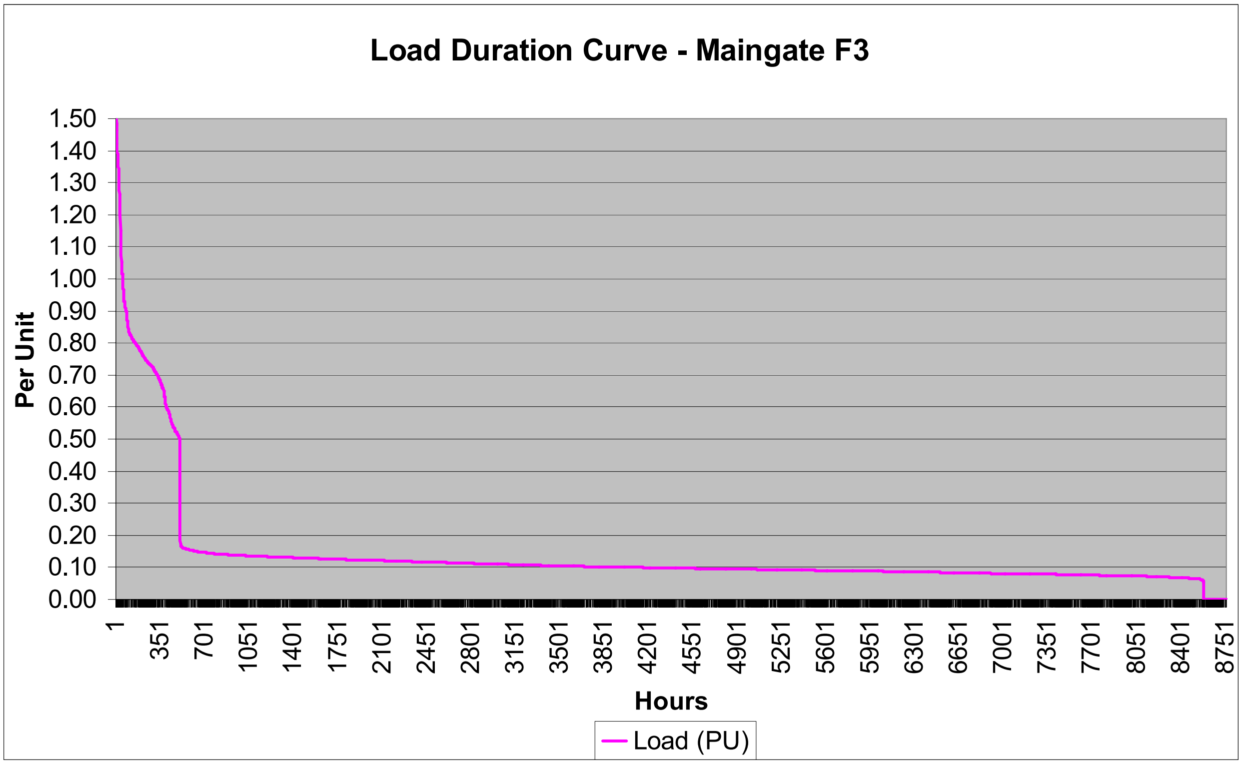
Maingate MS

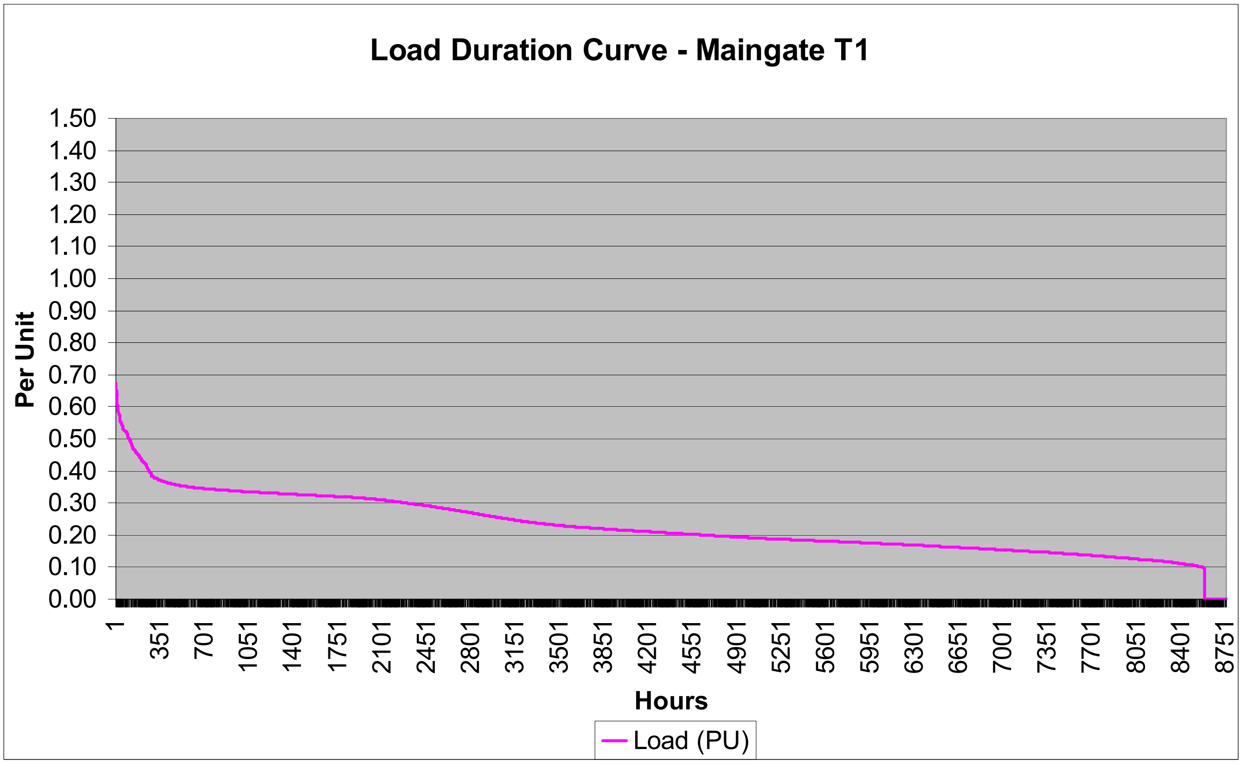


Load Duration Curve - Maingate F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Maingate F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Maingate F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Maingate T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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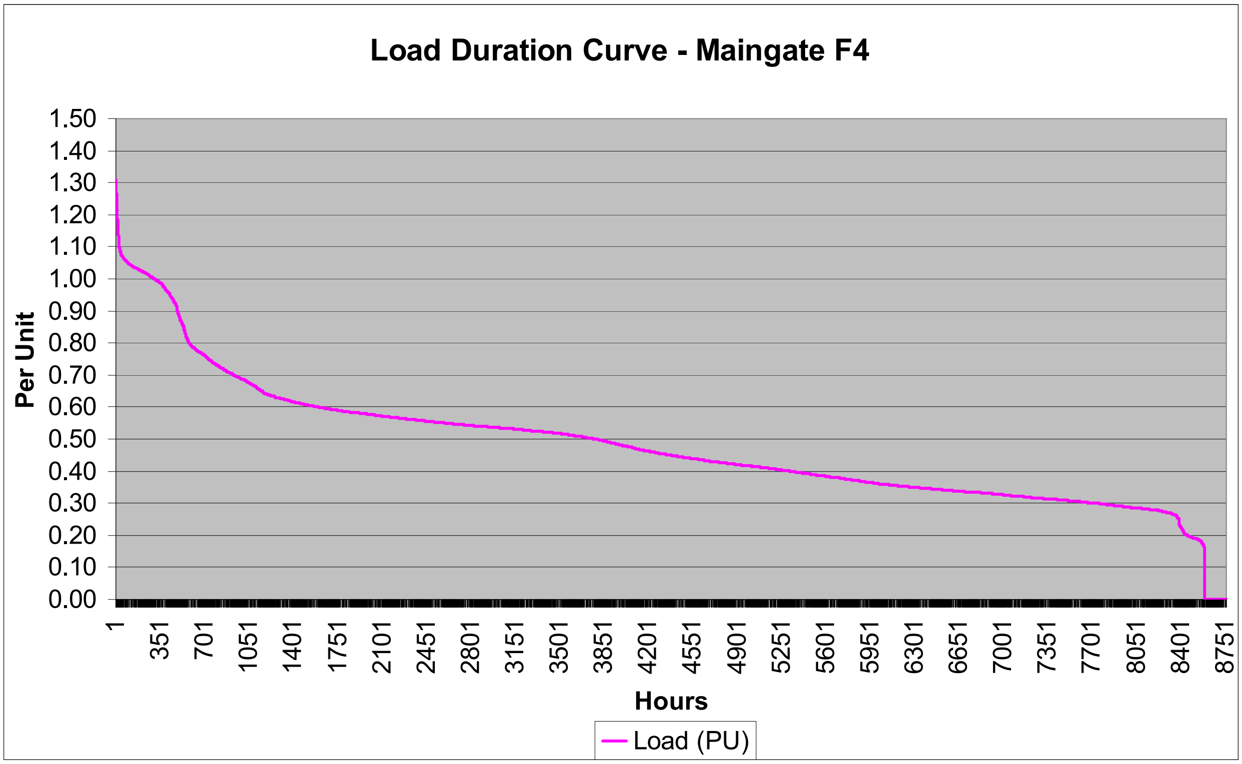
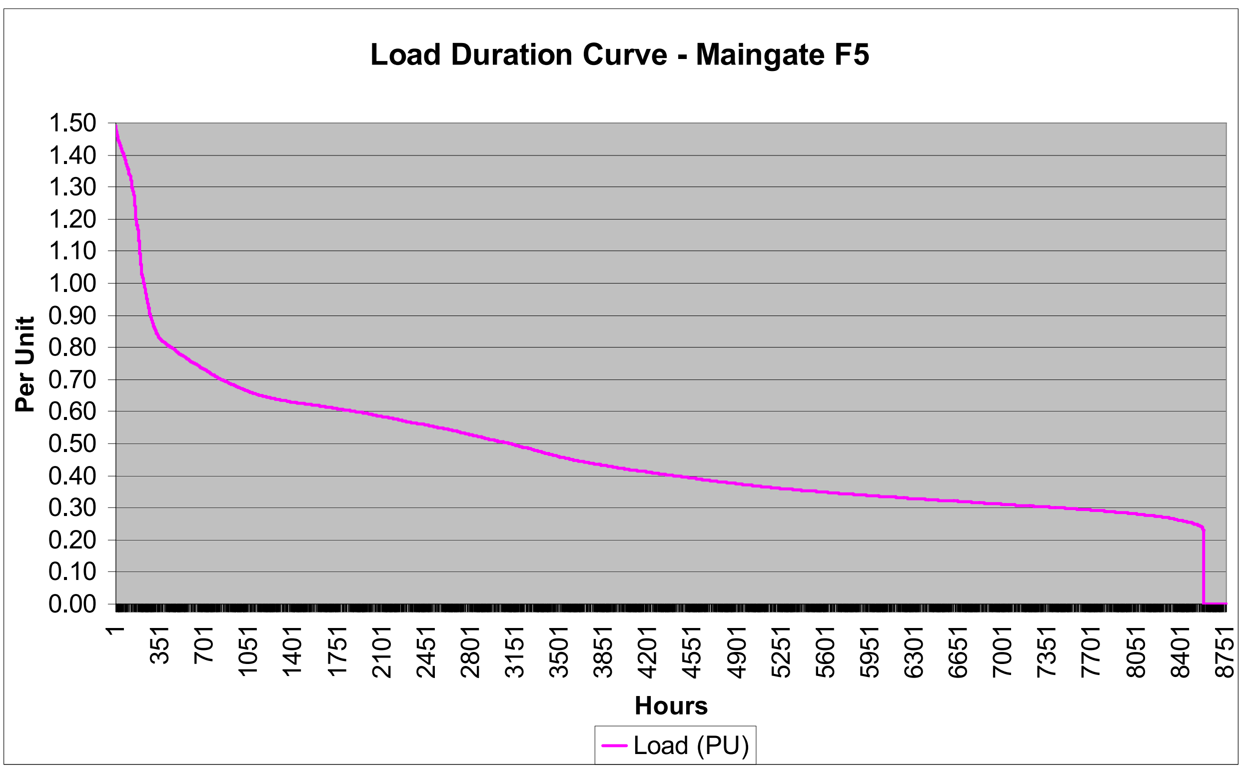
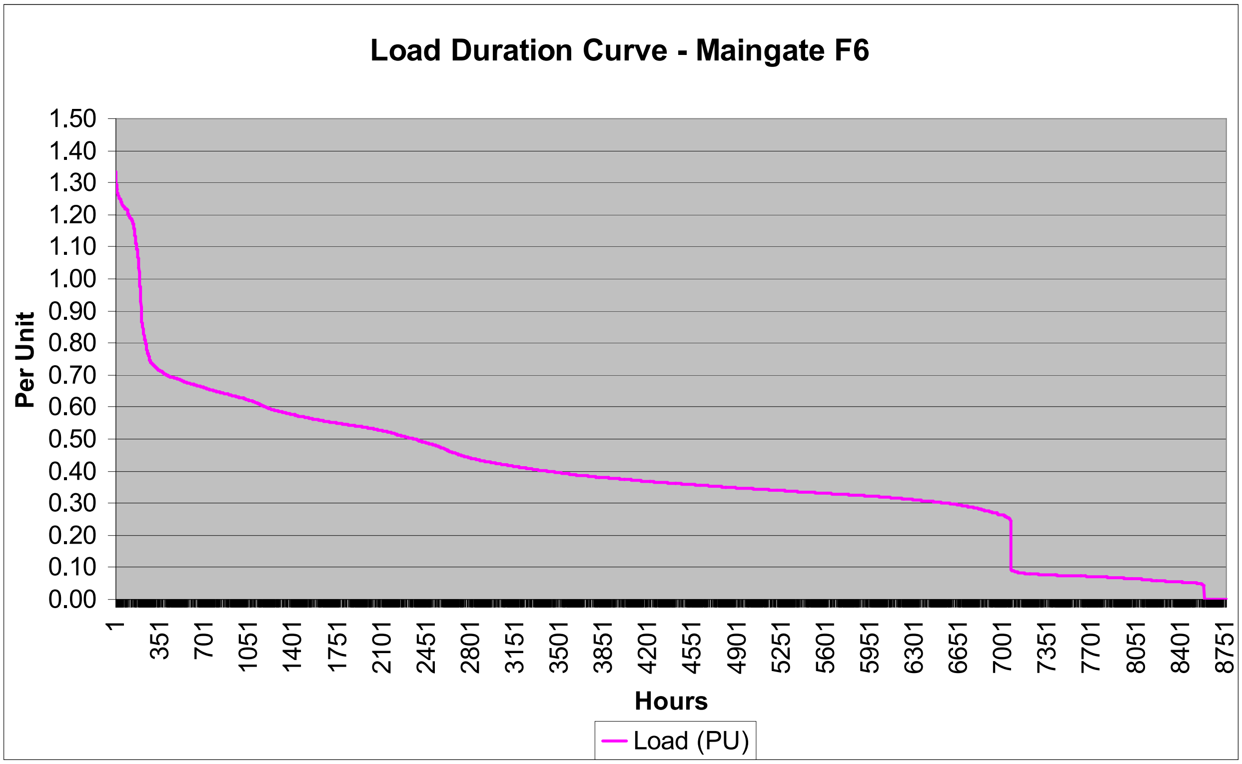
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Maingate F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Maingate F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Maingate F6
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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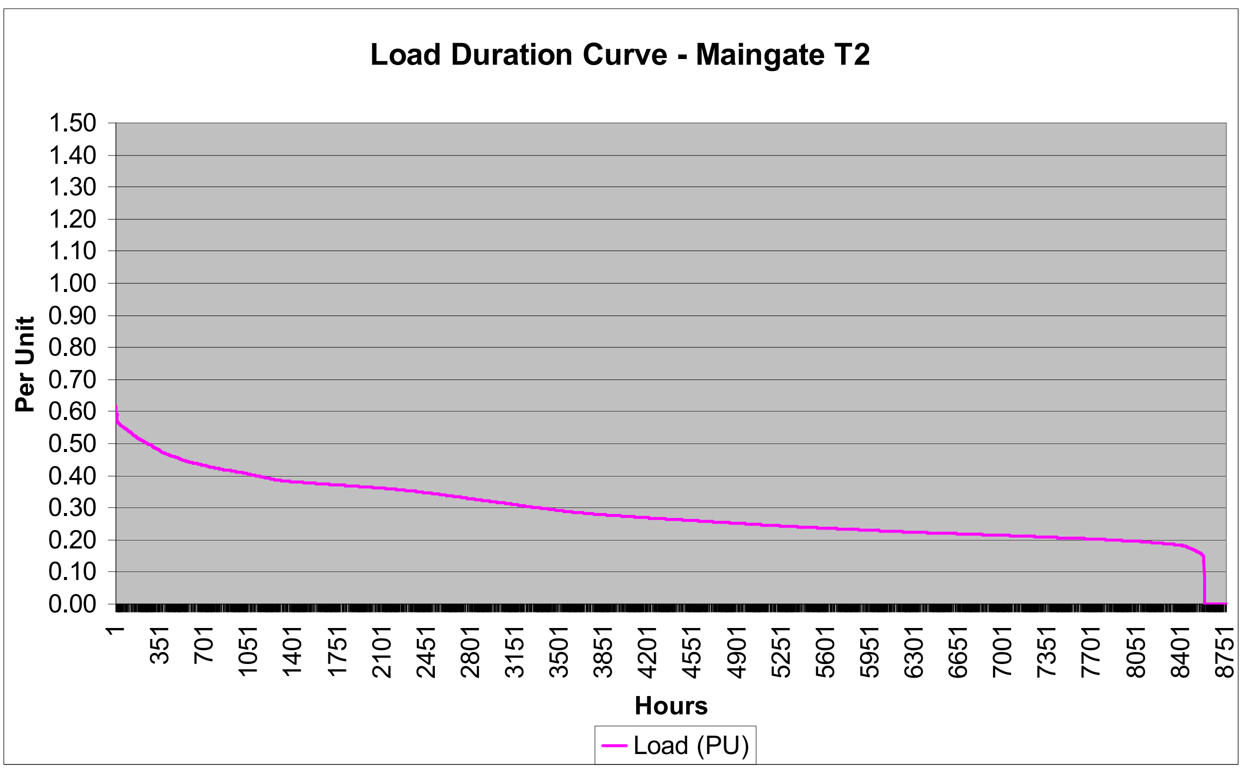
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Maingate T2
1.50
1.40
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
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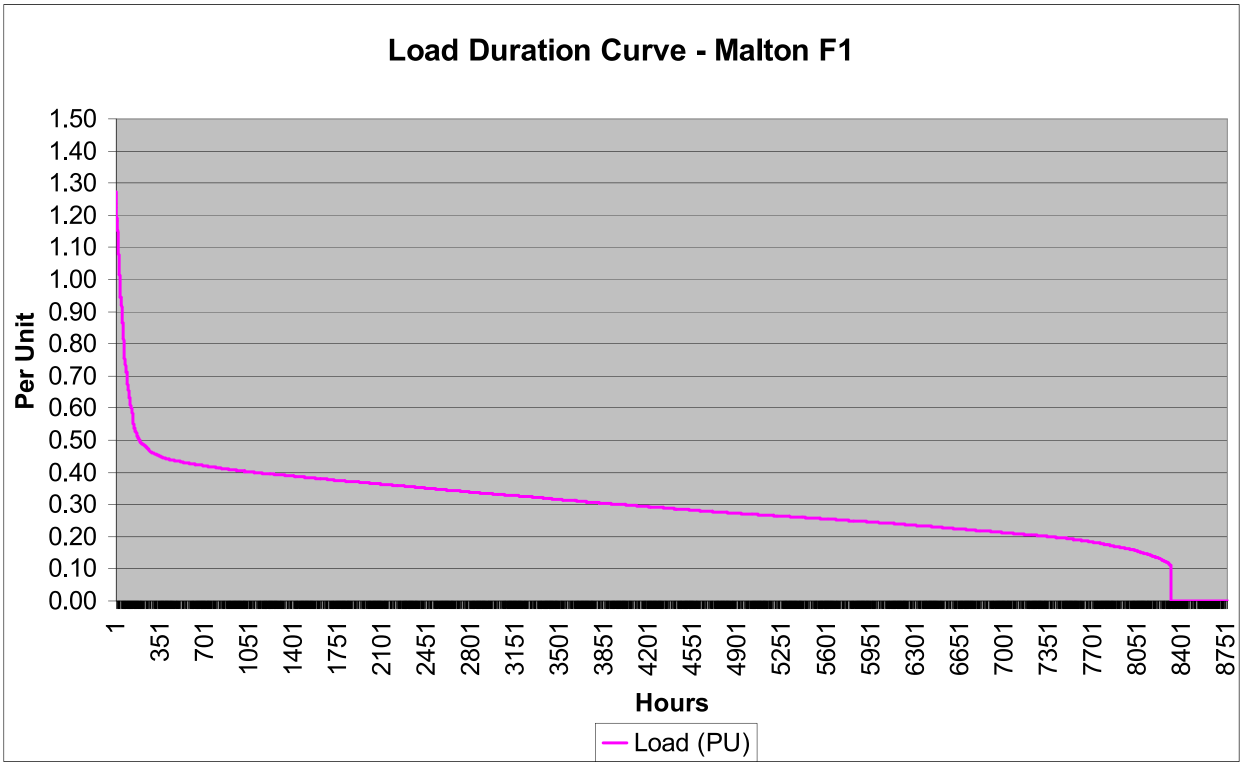
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Malton MS


Load Duration Curve - Malton F1
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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7351
7701
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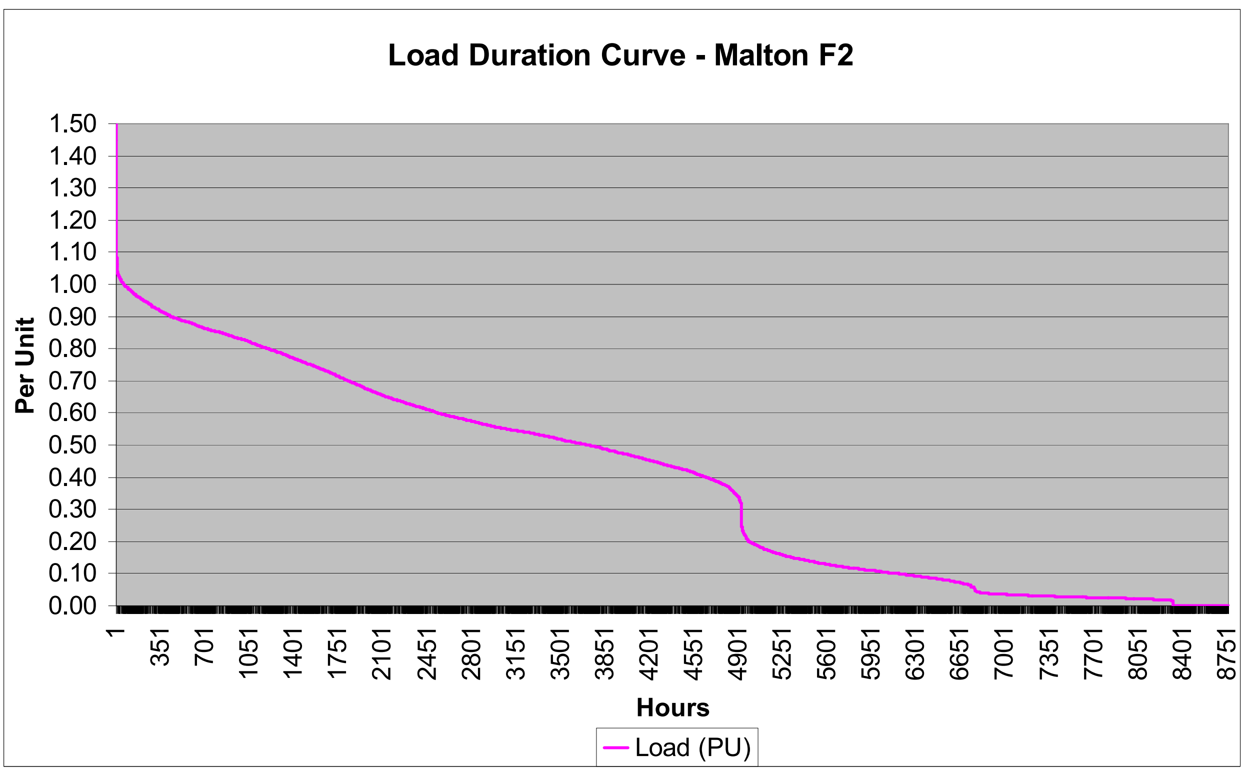
8401
8751
Hours
Load (PU)


Load Duration Curve - Malton F2
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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6301
6651
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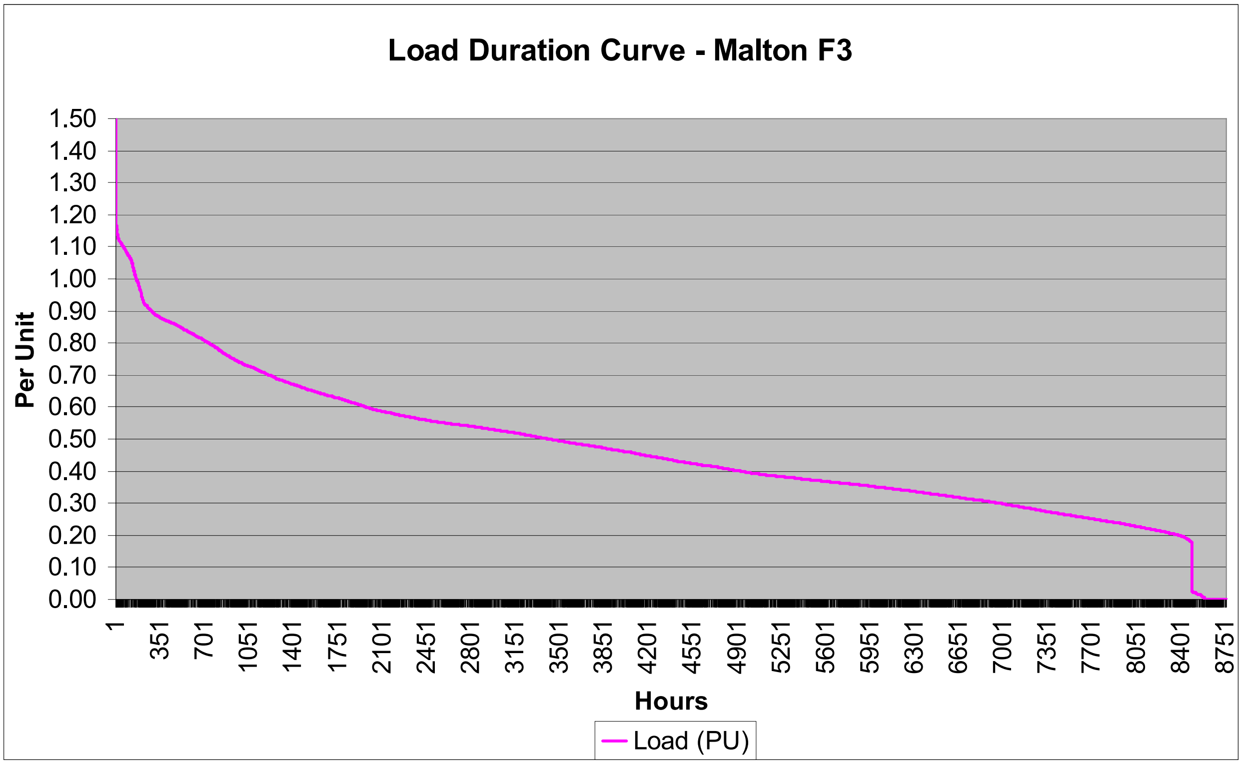
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Malton F3
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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6651
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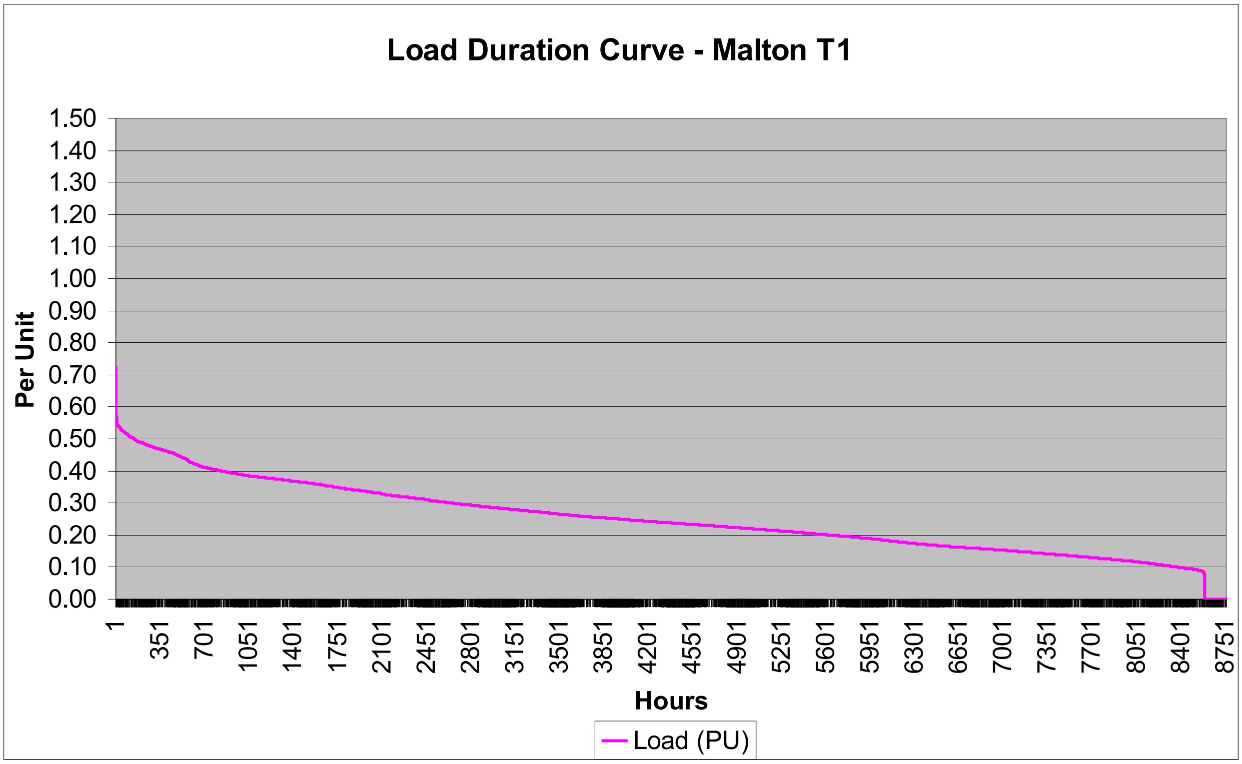
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Malton T1
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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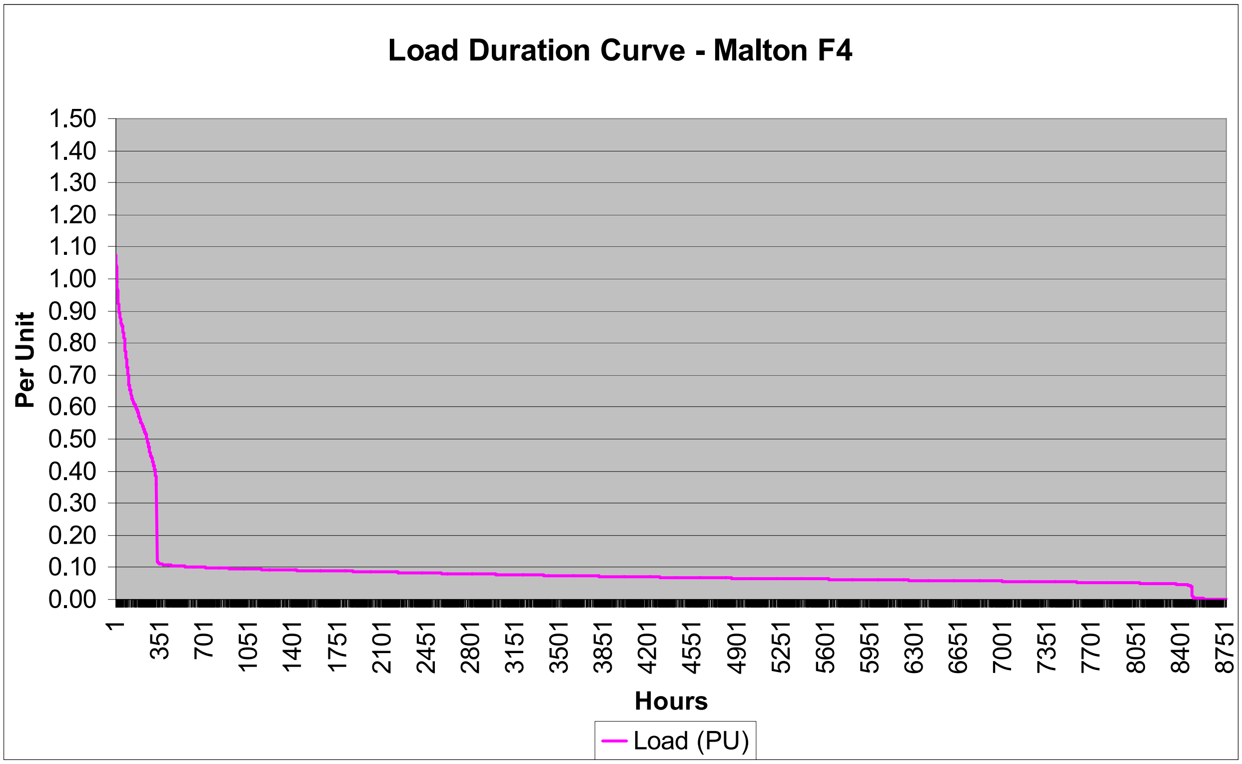
Hours
Load (PU)


Load Duration Curve - Malton F4
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
5951
6301
6651
7001
7351
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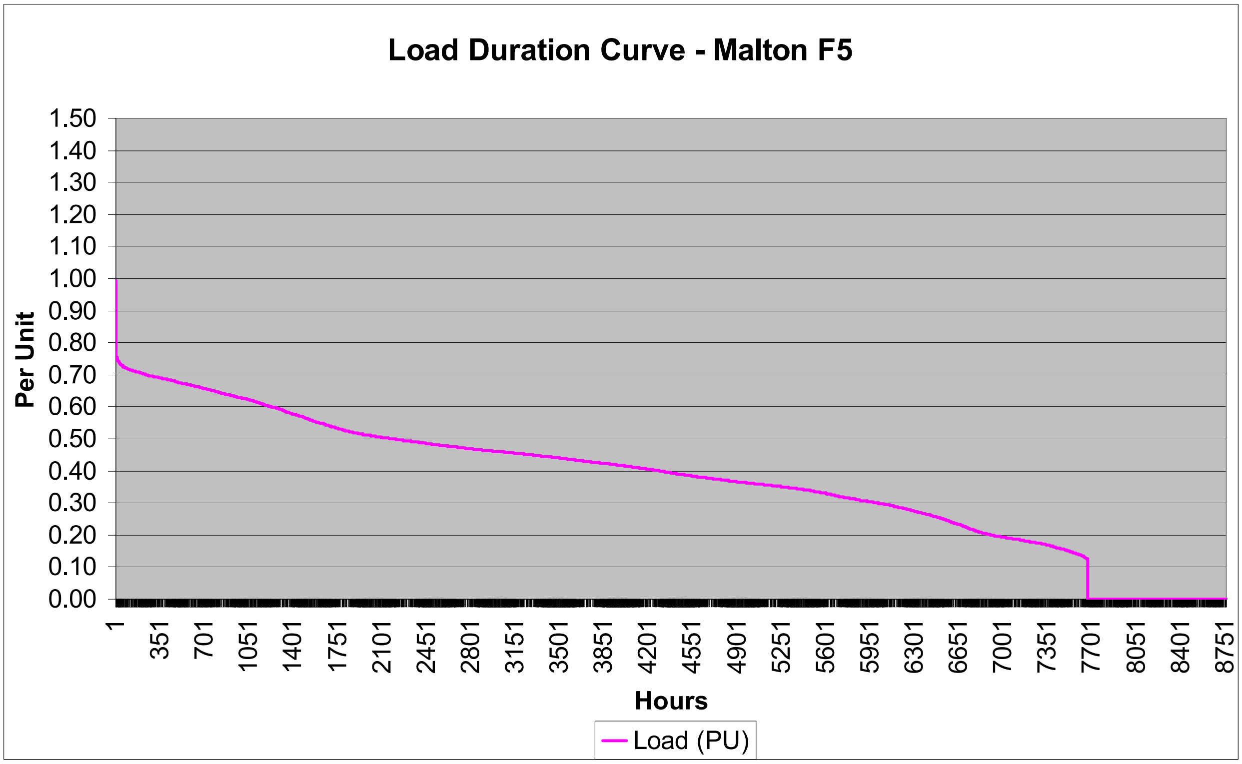
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Malton F5
Per Unit
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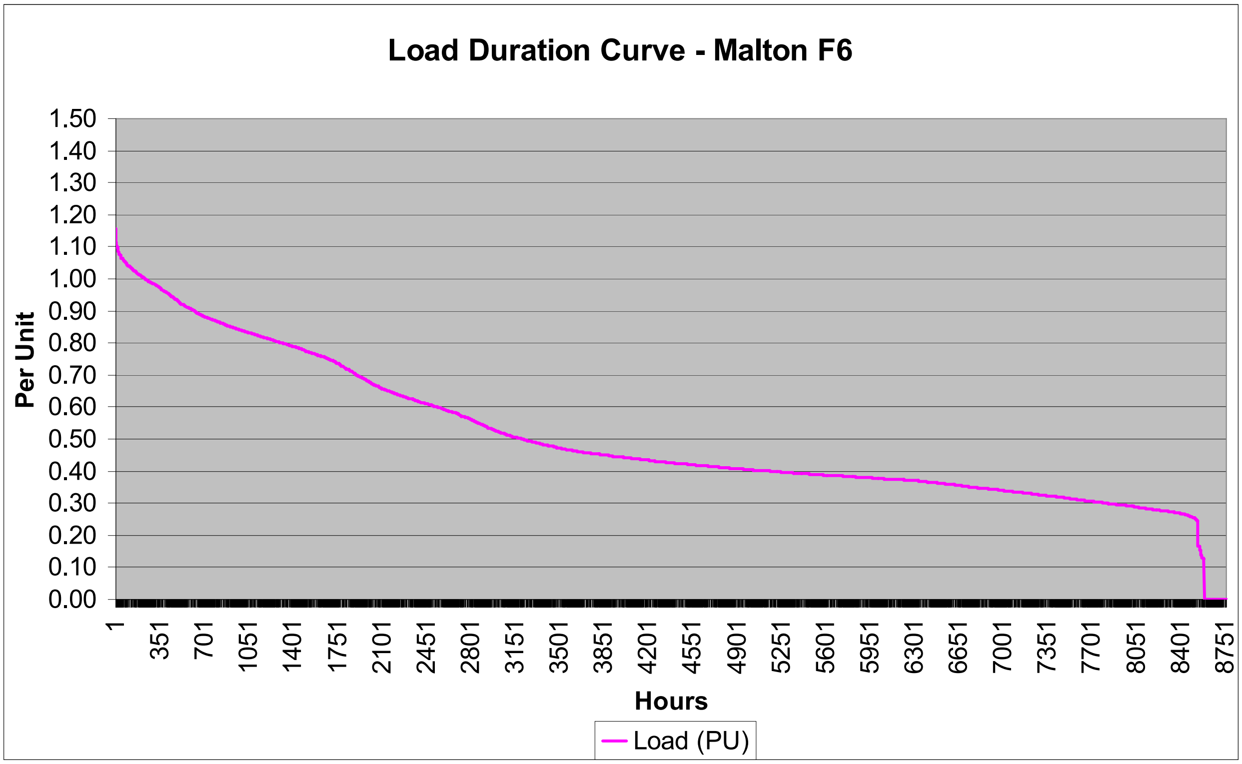
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Malton F6
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
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3851
4201
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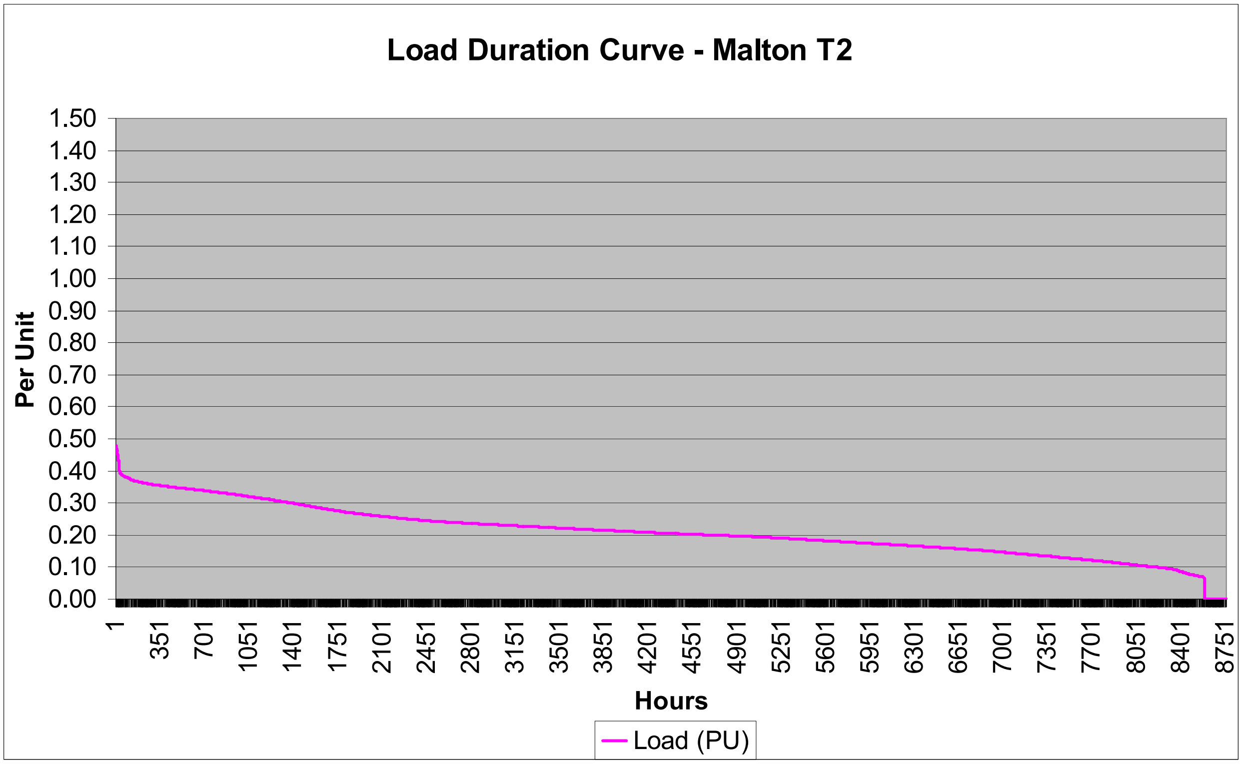
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Malton T2
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
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3151
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3851
4201
4551
4901
5251
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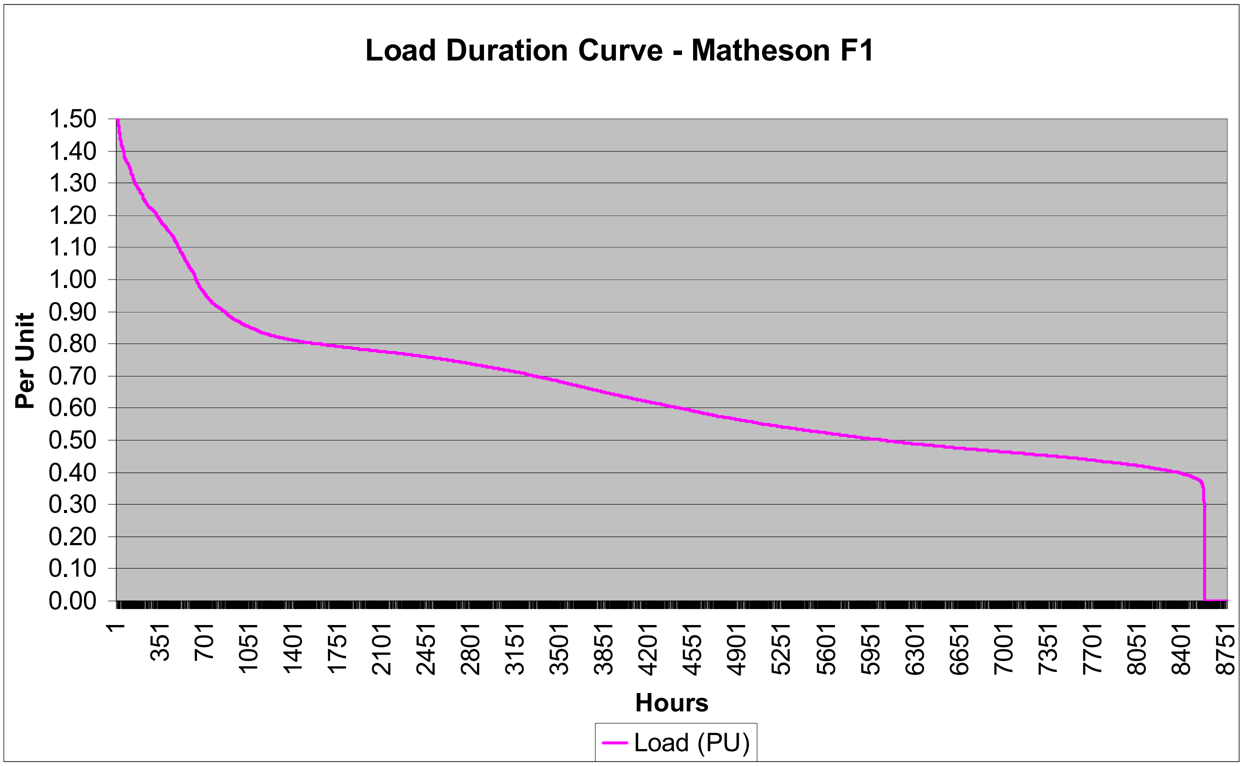
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Matheson MS


Load Duration Curve - Matheson F1
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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7351
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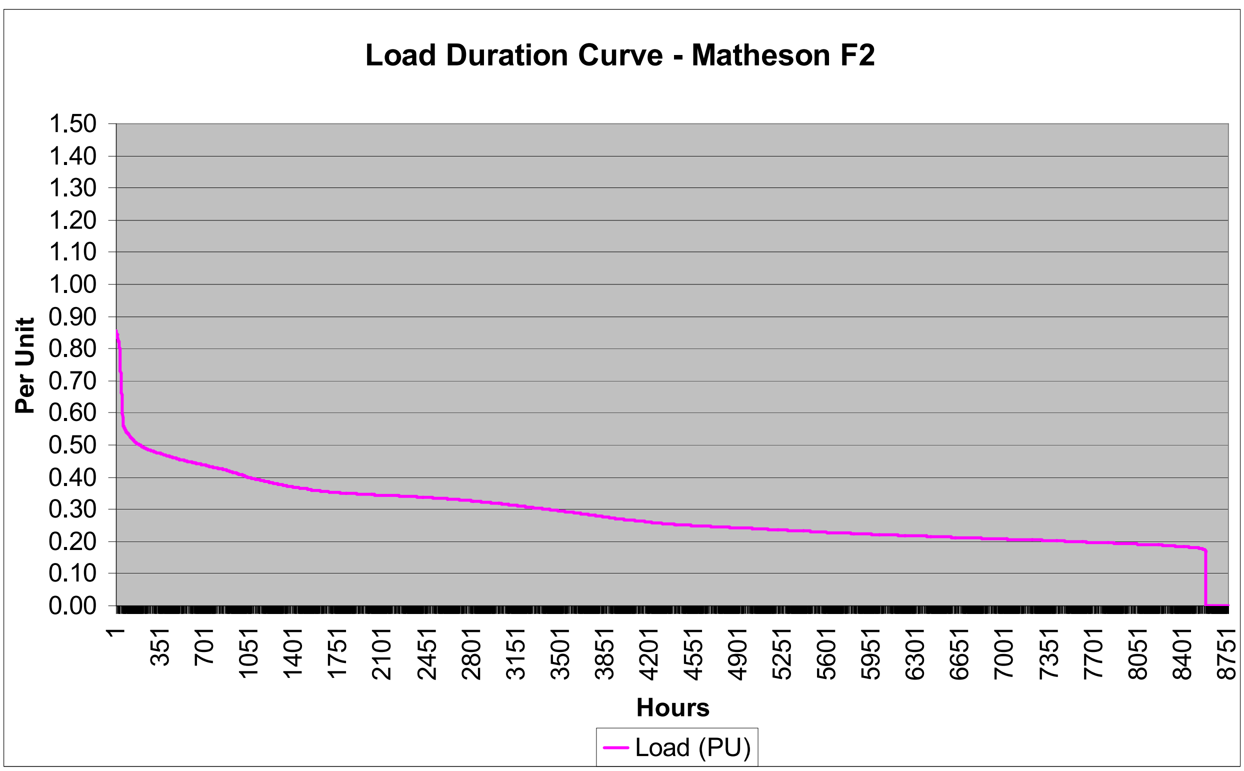
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson F2
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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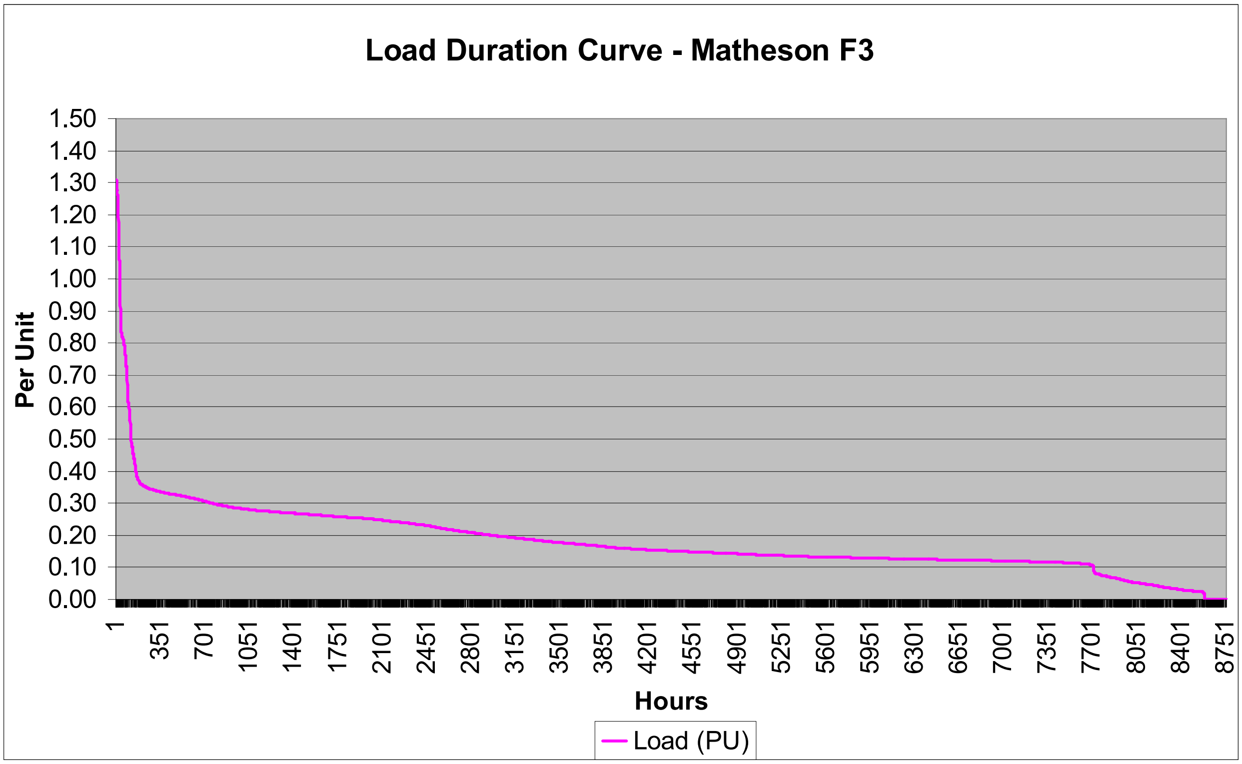
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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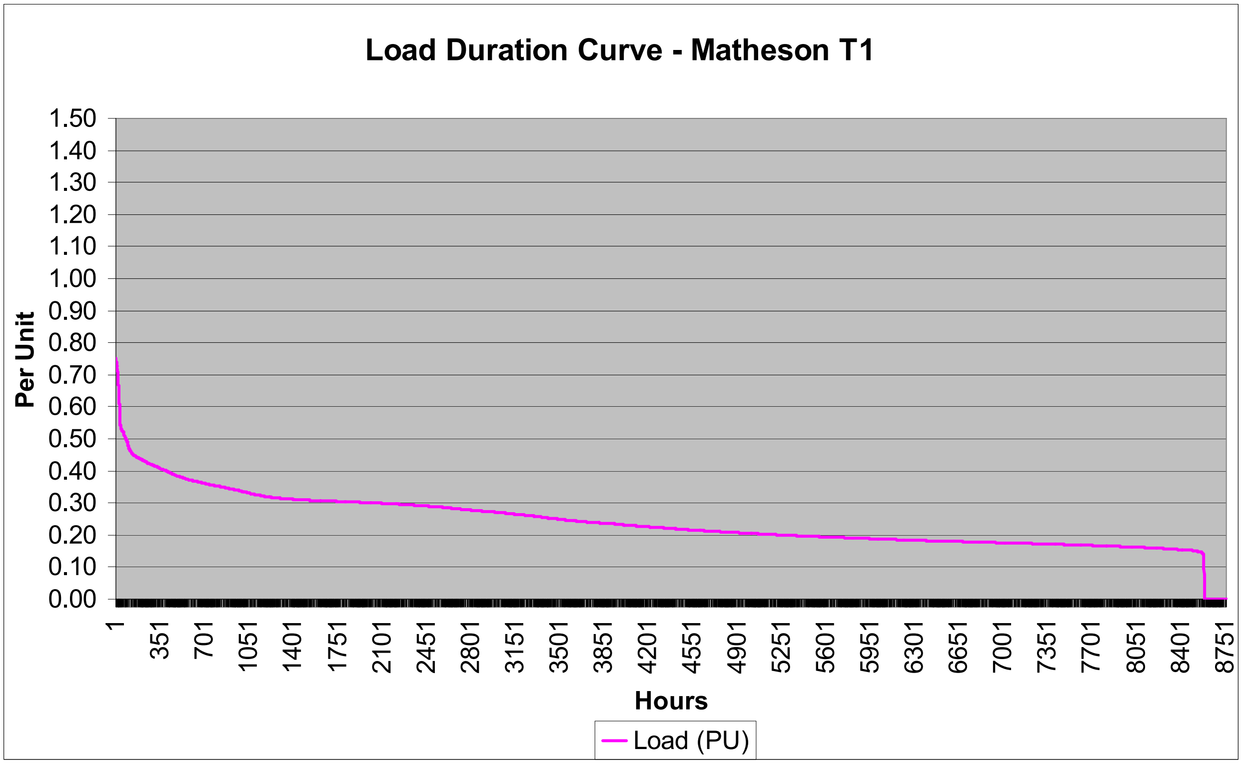
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson T1
Per Unit
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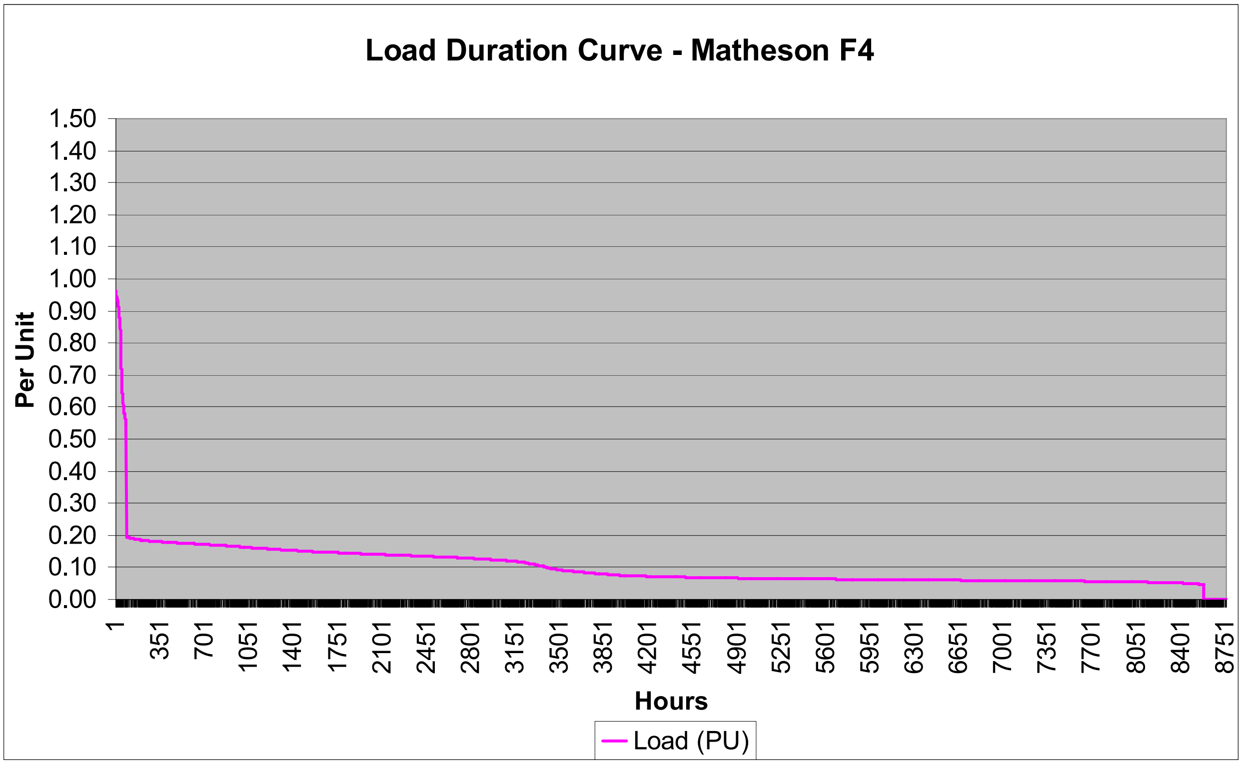
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson F4
Per Unit
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1.40
1.30
1.20
1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6301
6651
7001
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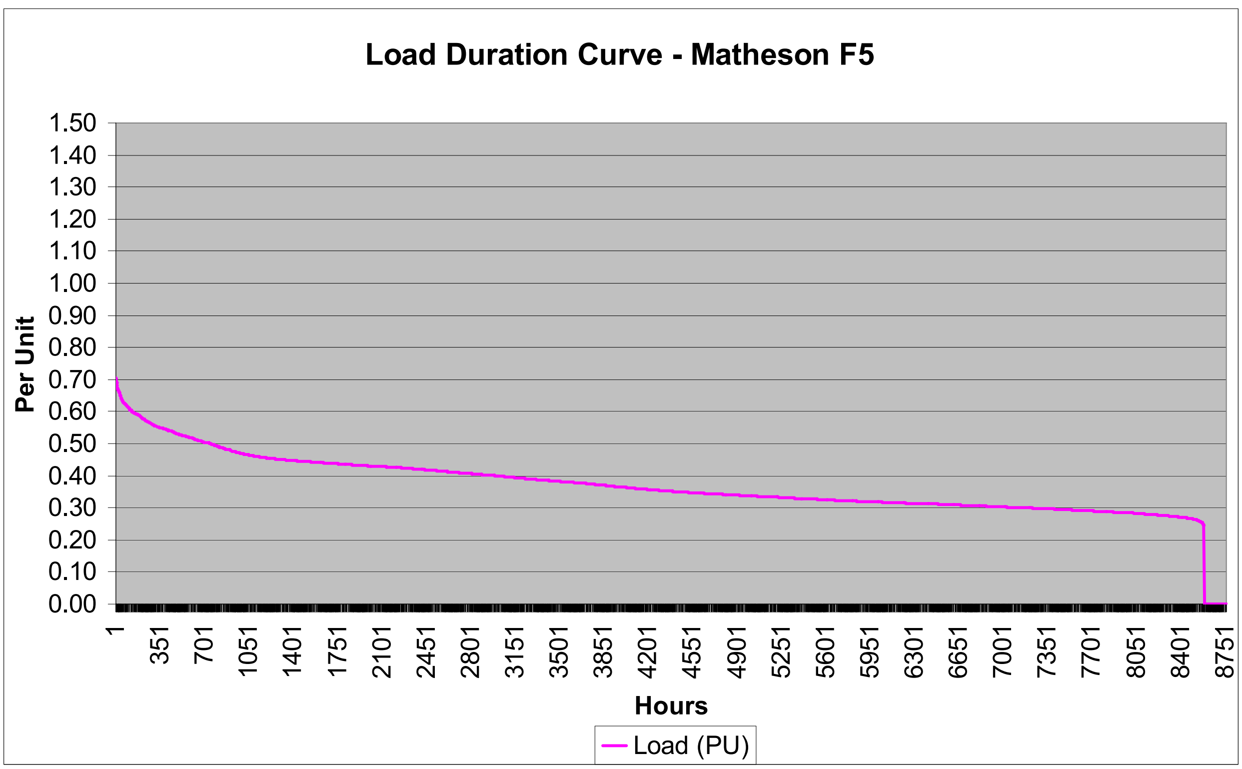
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson F5
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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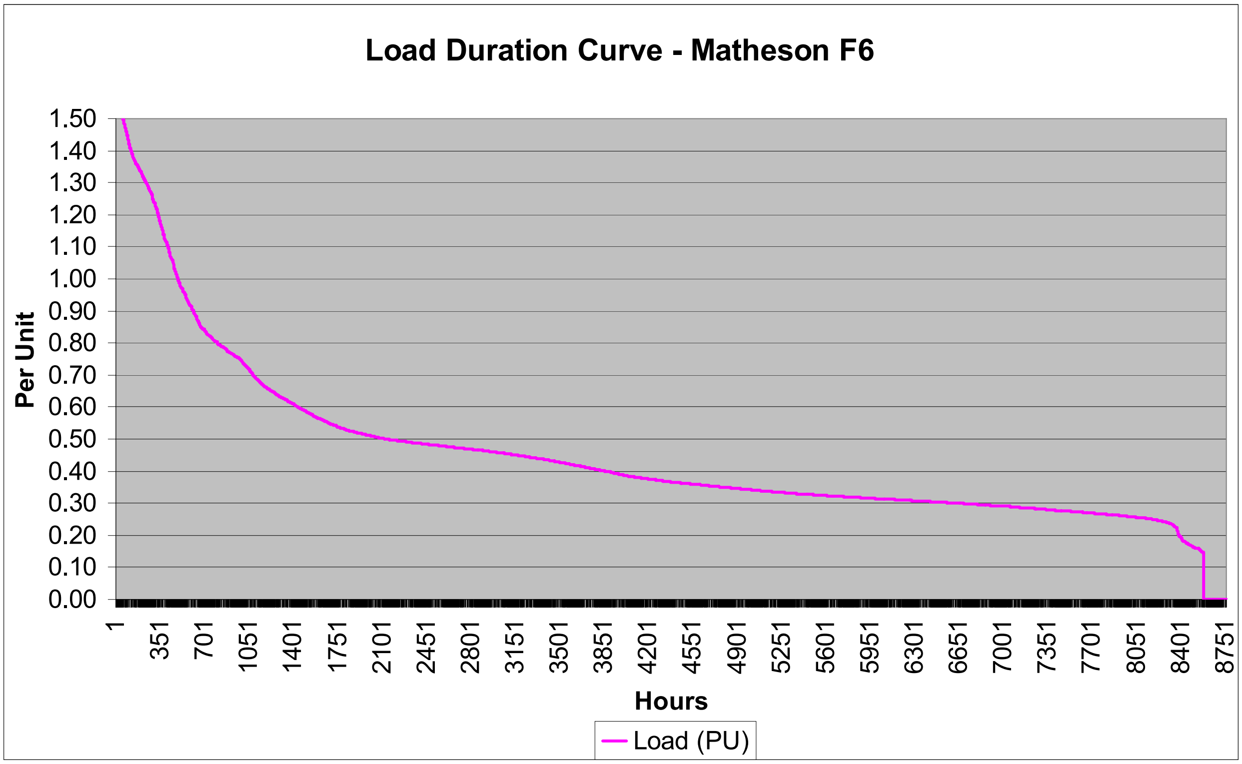
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson F6
Per Unit
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1.10
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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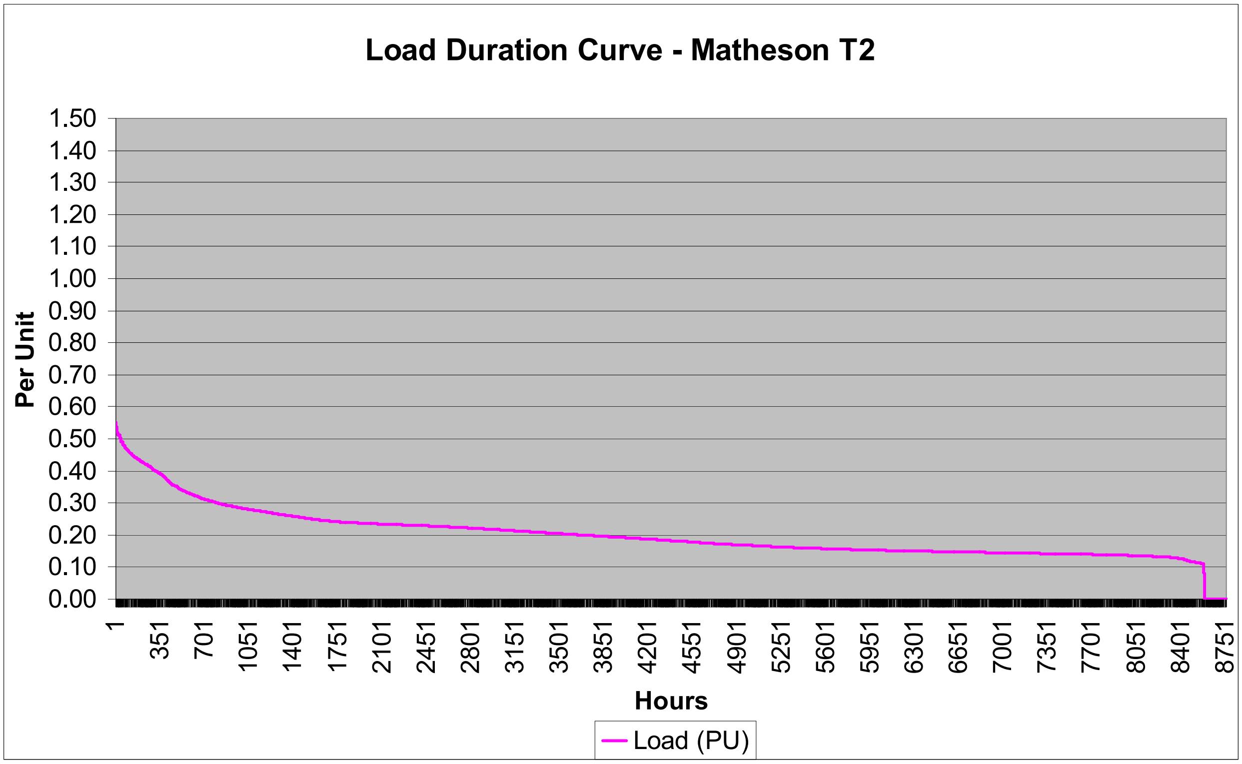
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Matheson T2
Per Unit
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1.40
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
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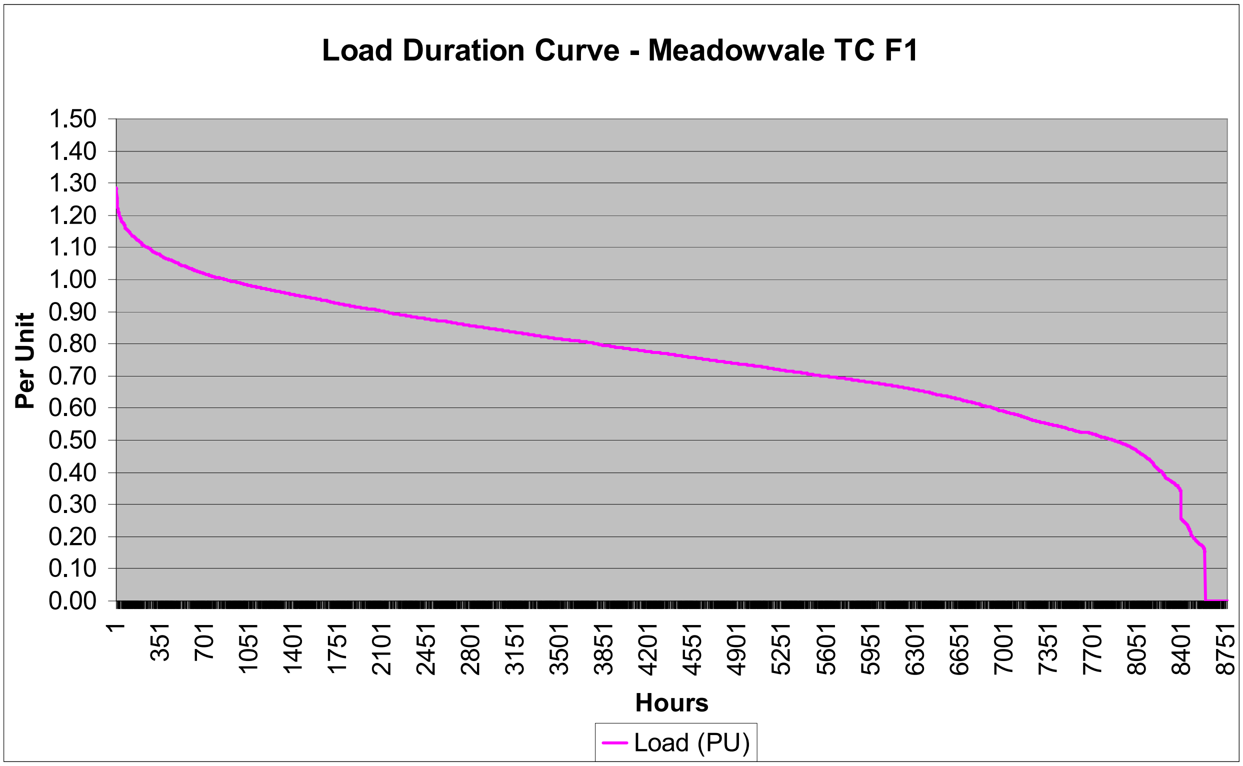
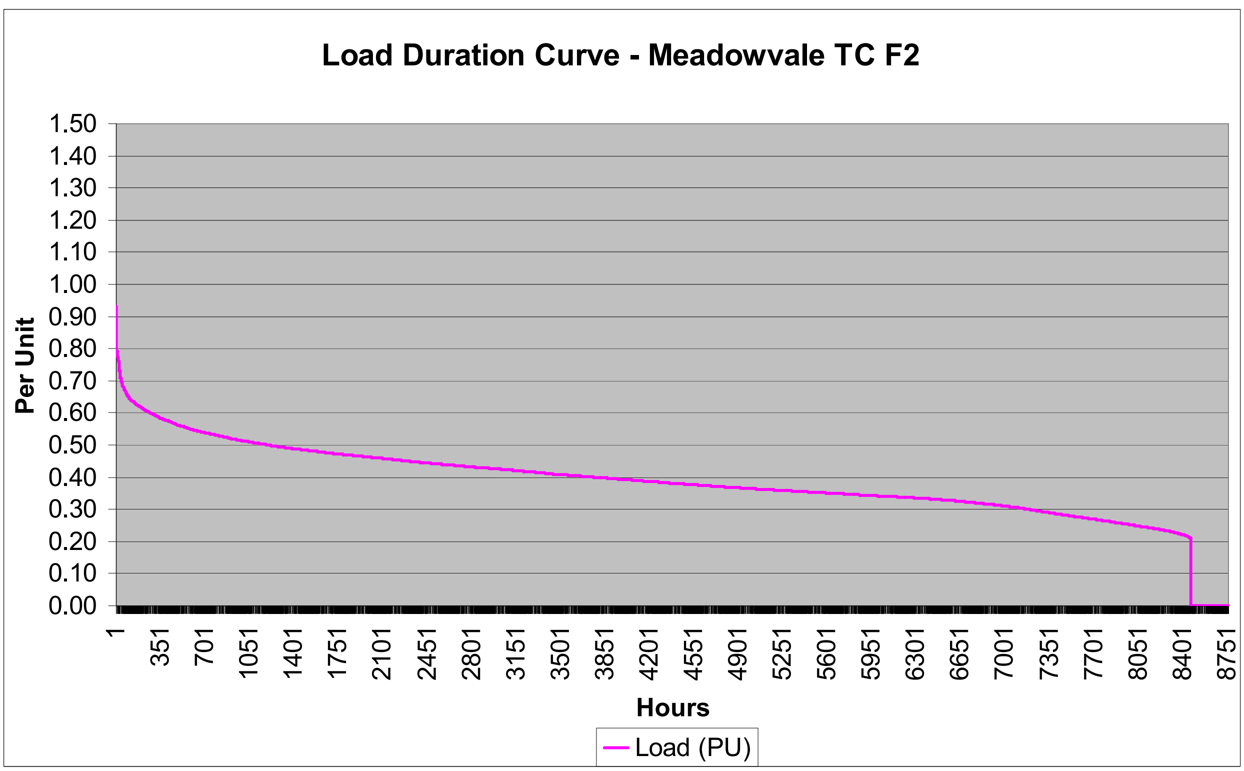
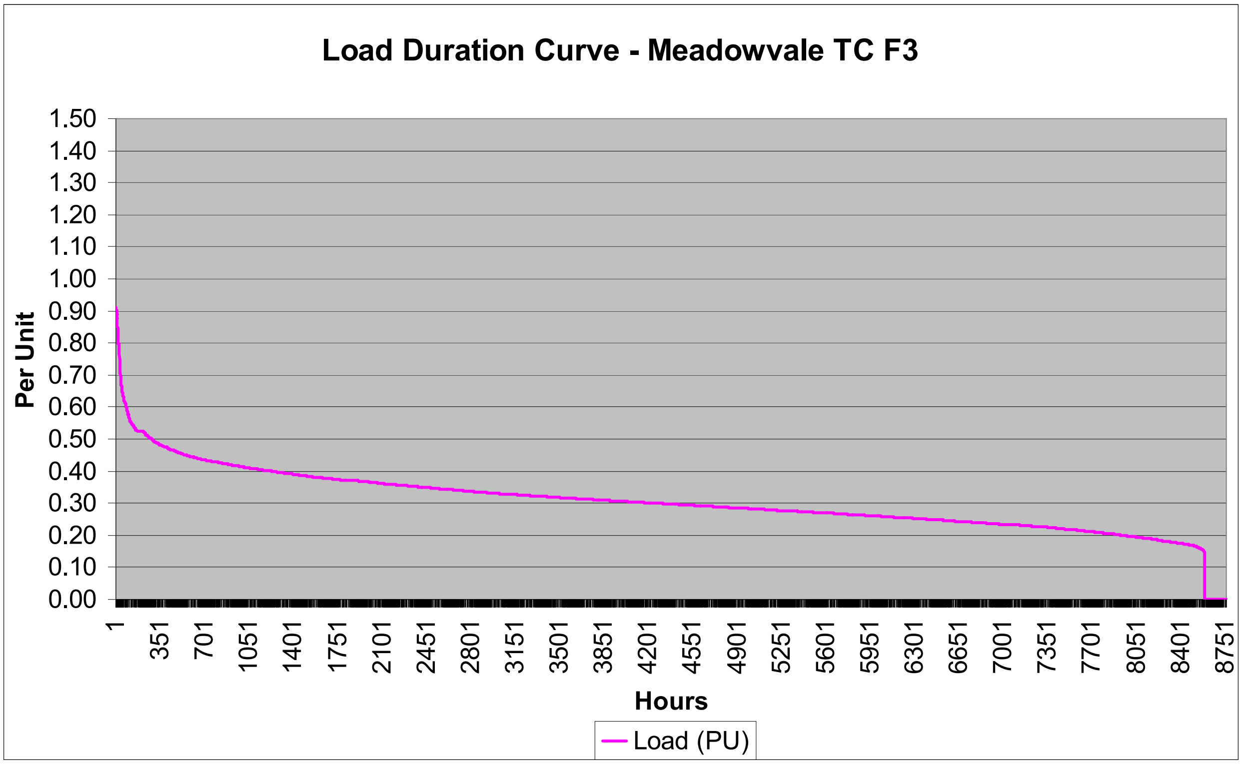
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Meadowvale Town Centre MS







Load Duration Curve - Meadowvale TC F3
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
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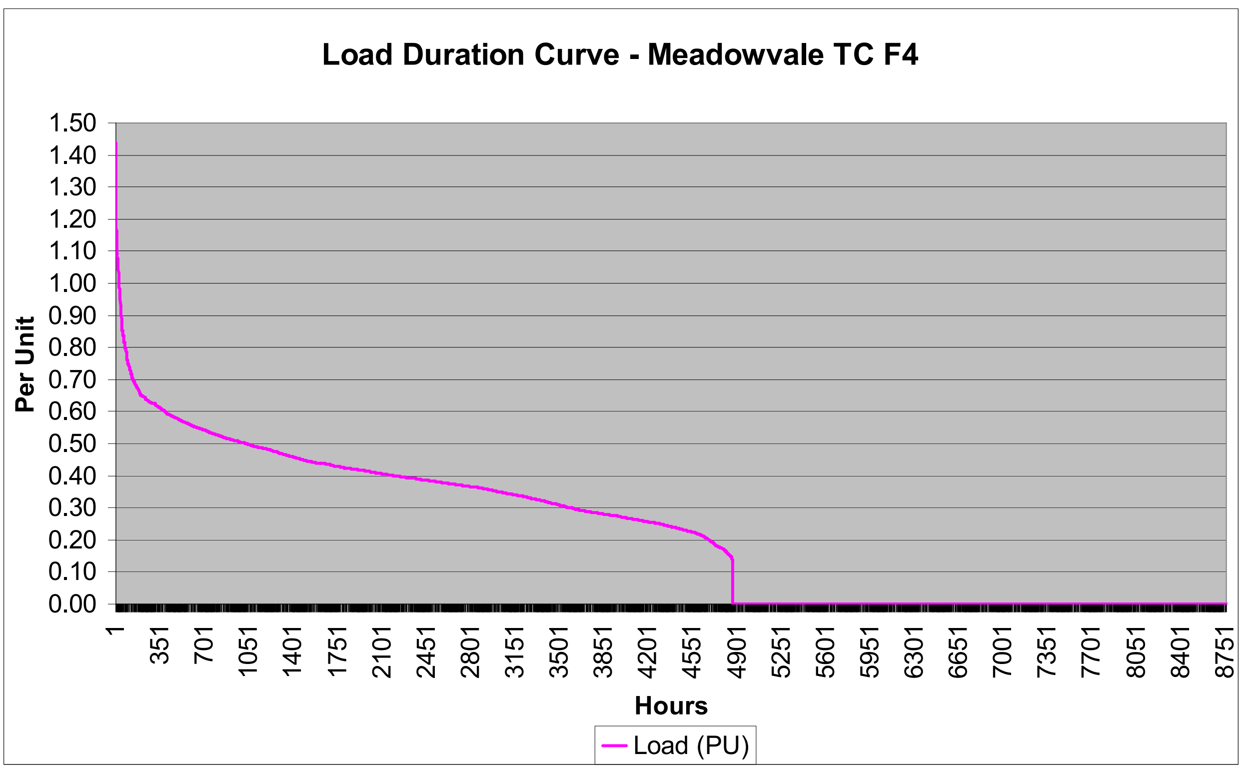
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Meadowvale TC F4
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1.40
1.30
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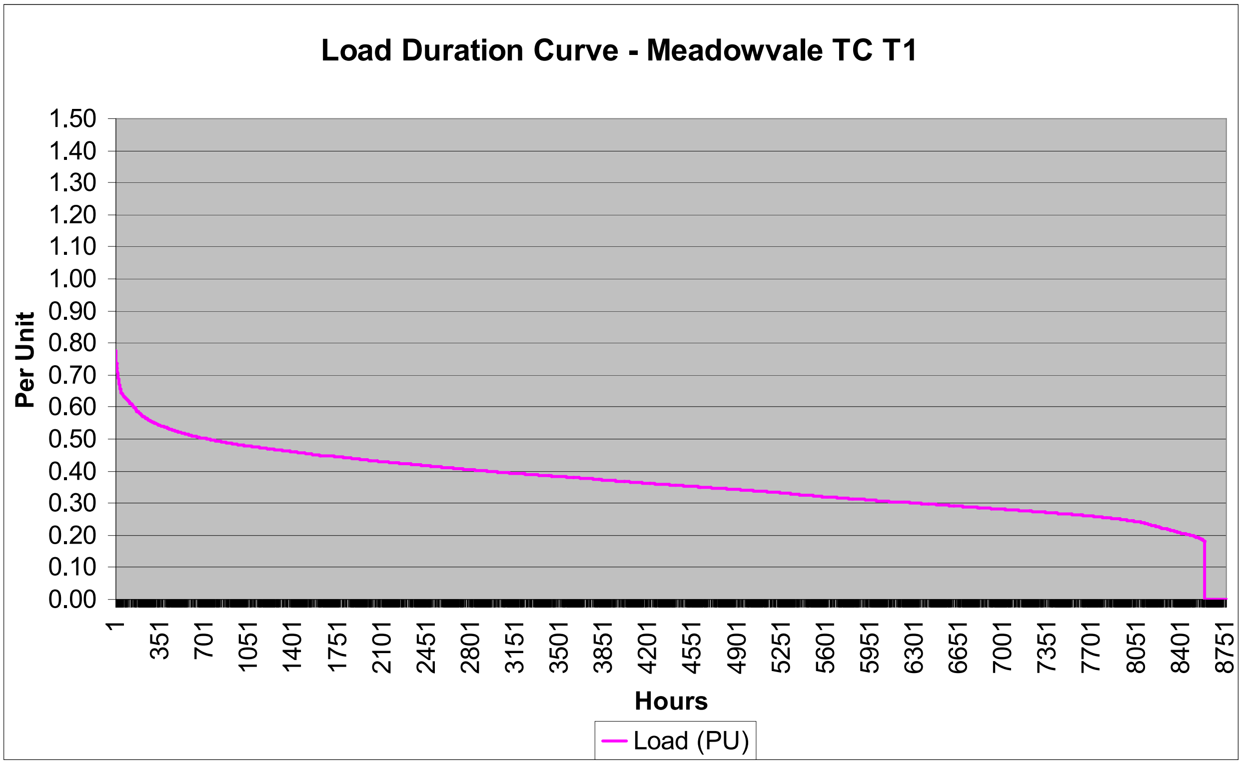
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Meadowvale TC T1
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
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3851
4201
4551
4901
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5601
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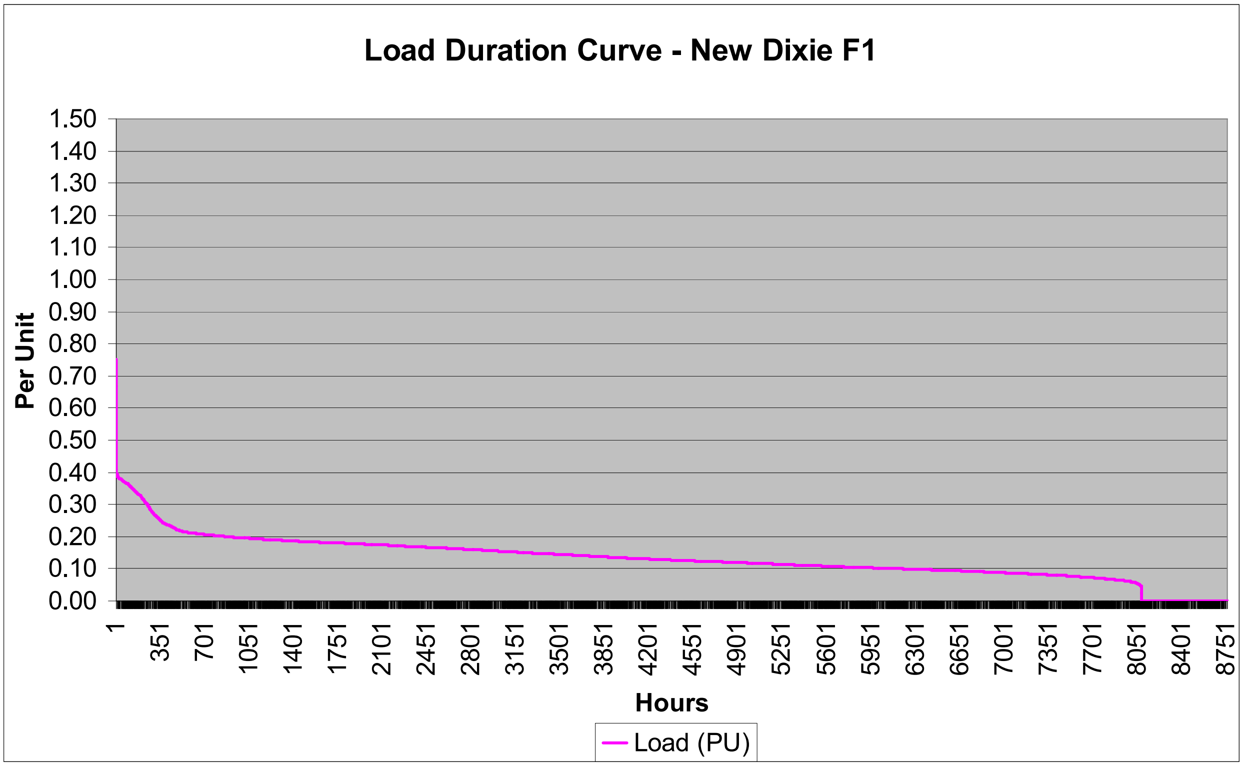
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

New Dixie MS



Load Duration Curve - New Dixie F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
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2101
2451
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3151
3501
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4201
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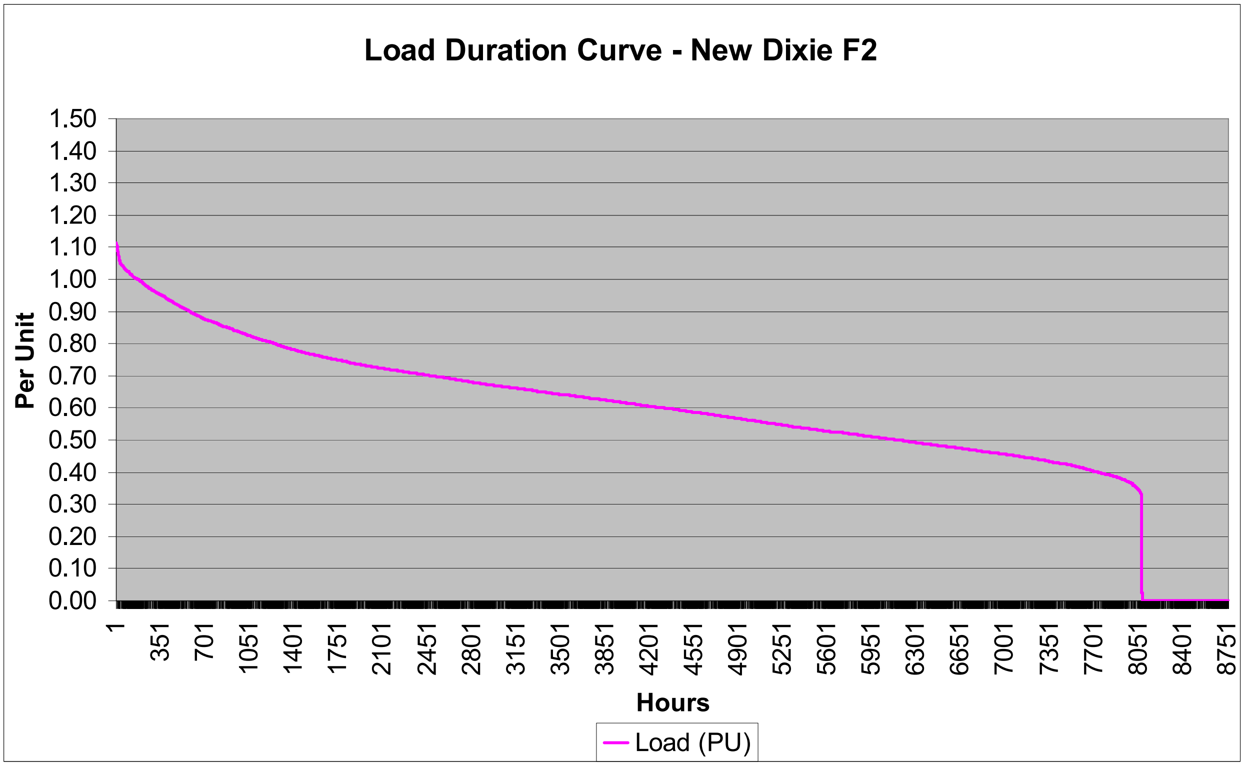
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - New Dixie F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
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4201
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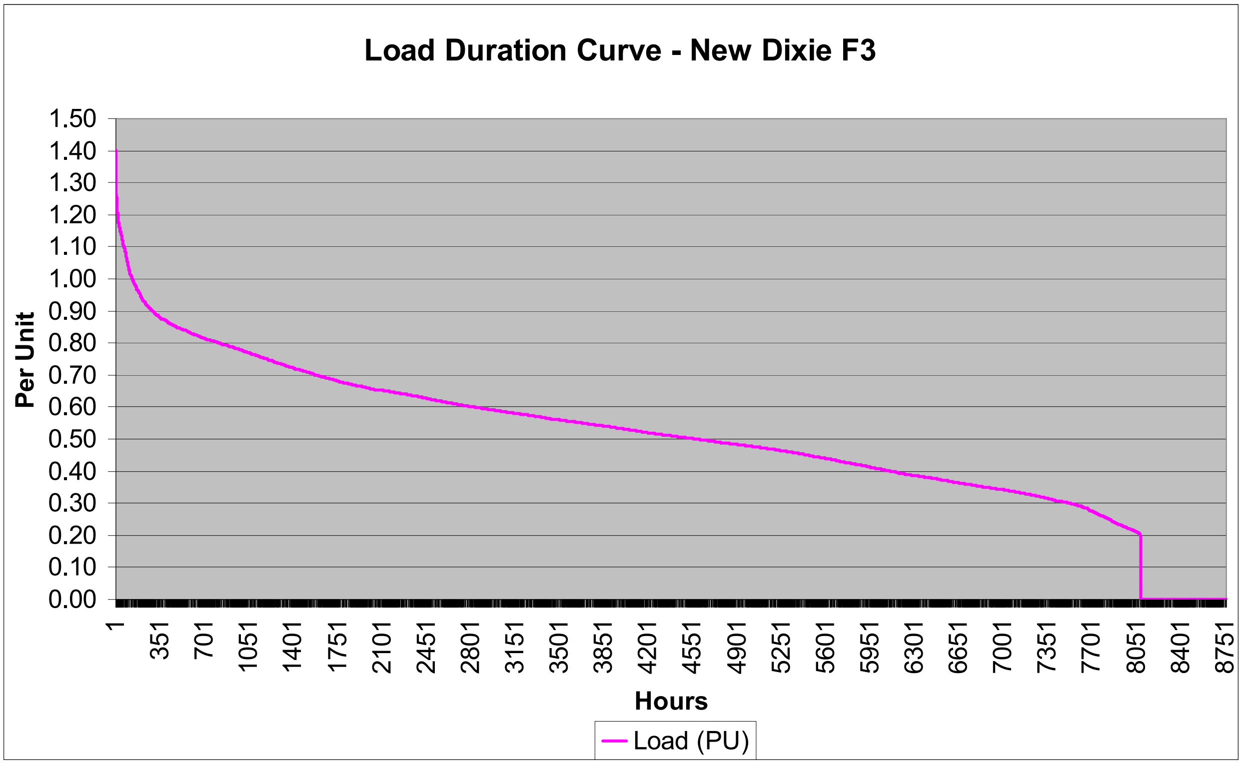
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - New Dixie F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6651
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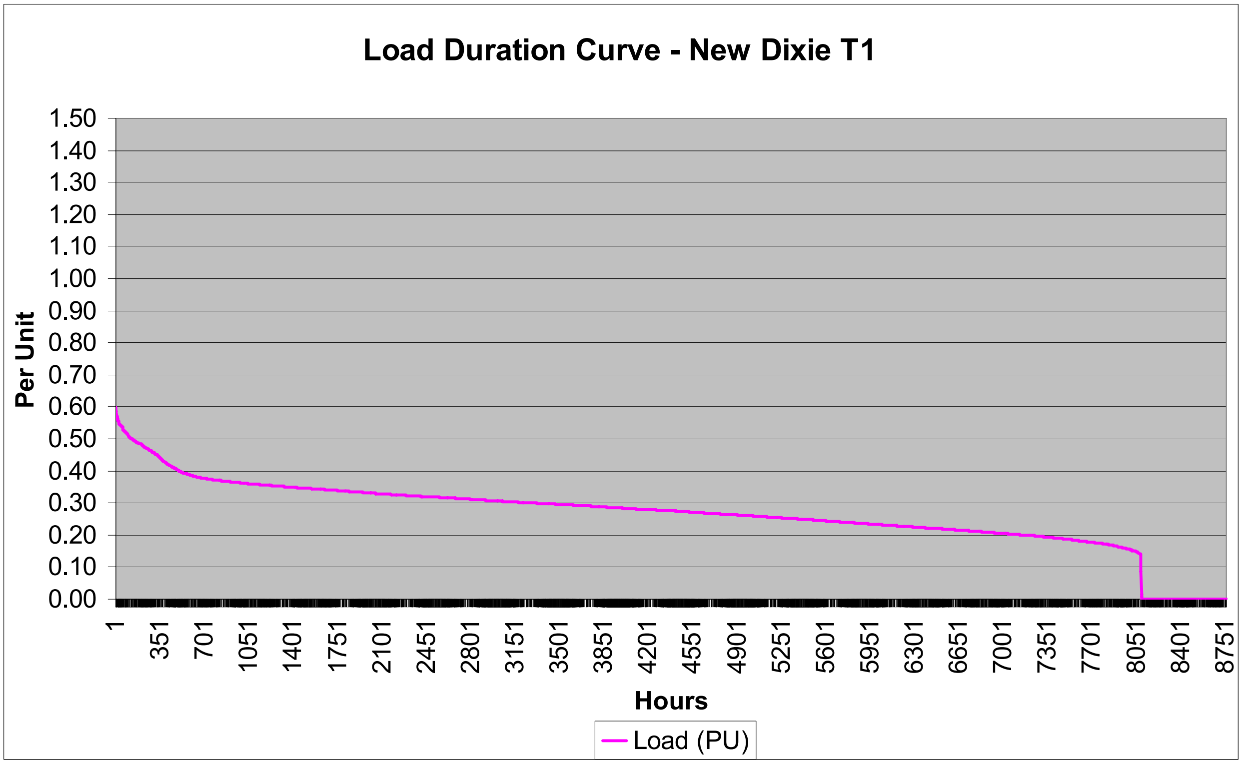
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - New Dixie T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
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351
701
1051
1401
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2101
2451
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3151
3501
3851
4201
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5251
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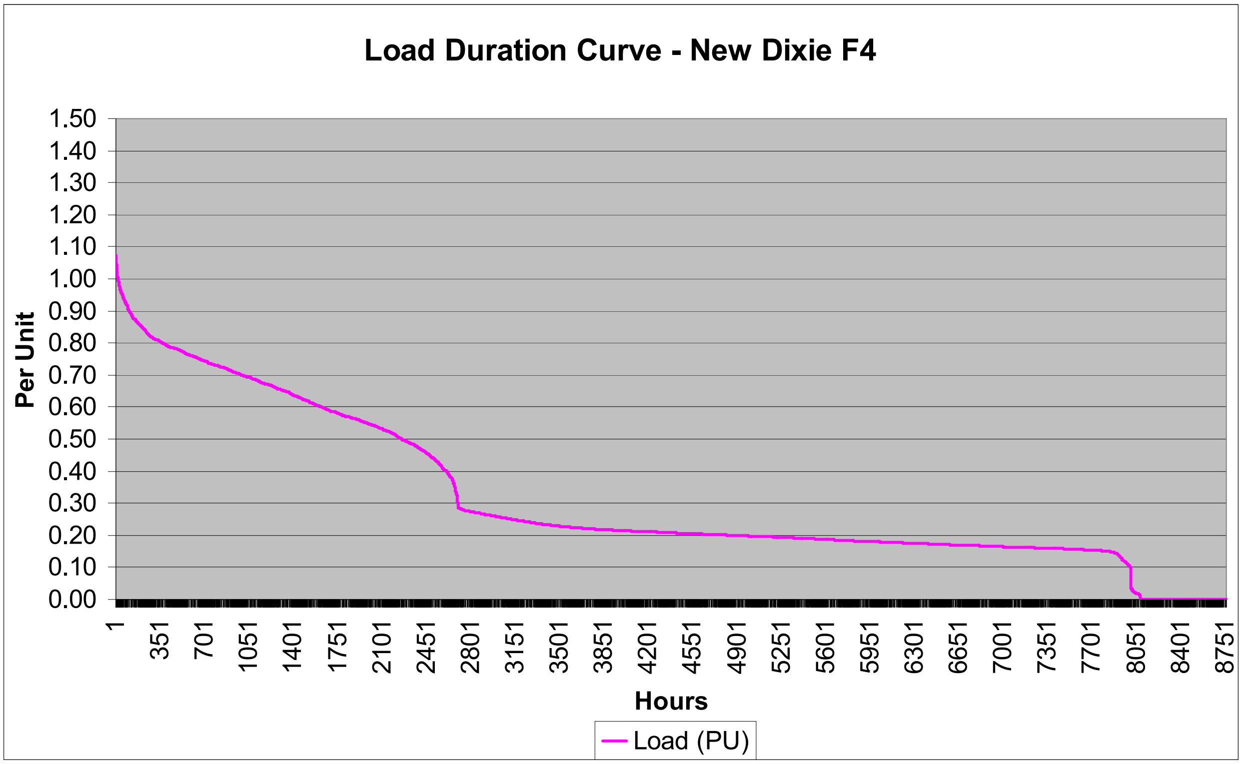
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - New Dixie F4
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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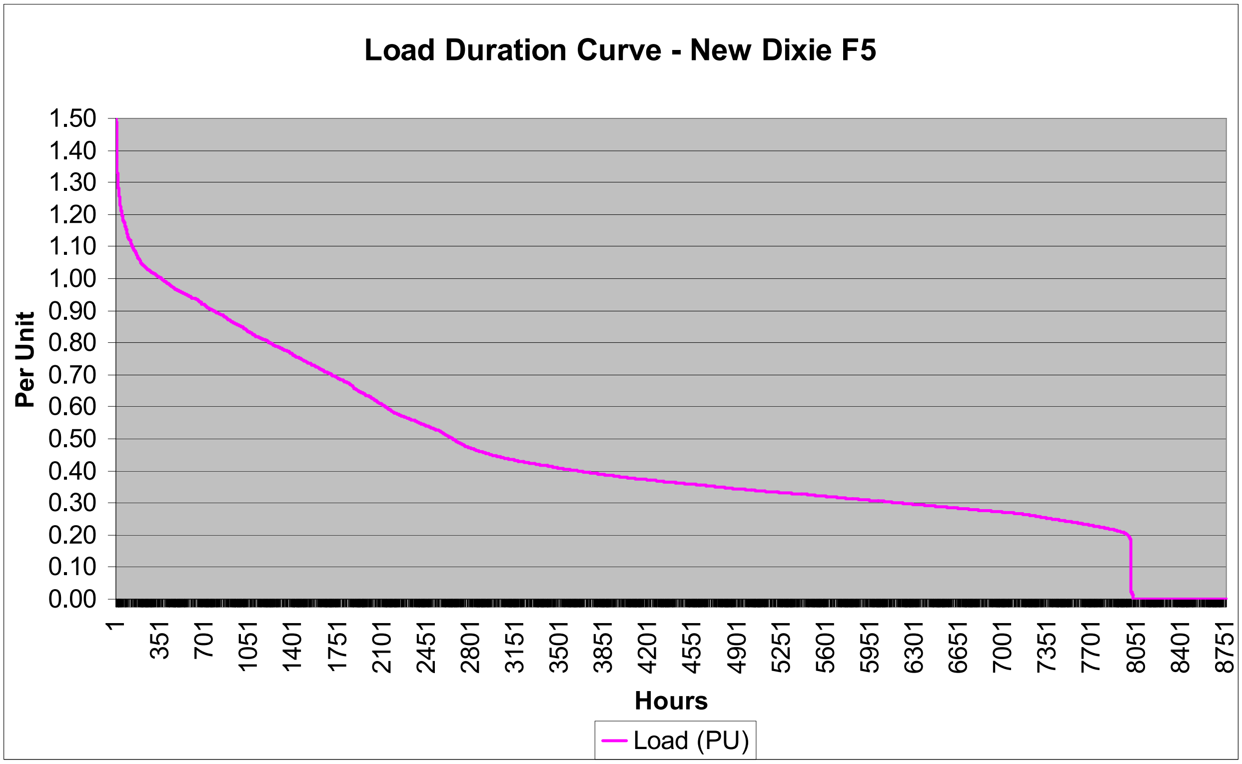
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - New Dixie F5
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5951
6301
6651
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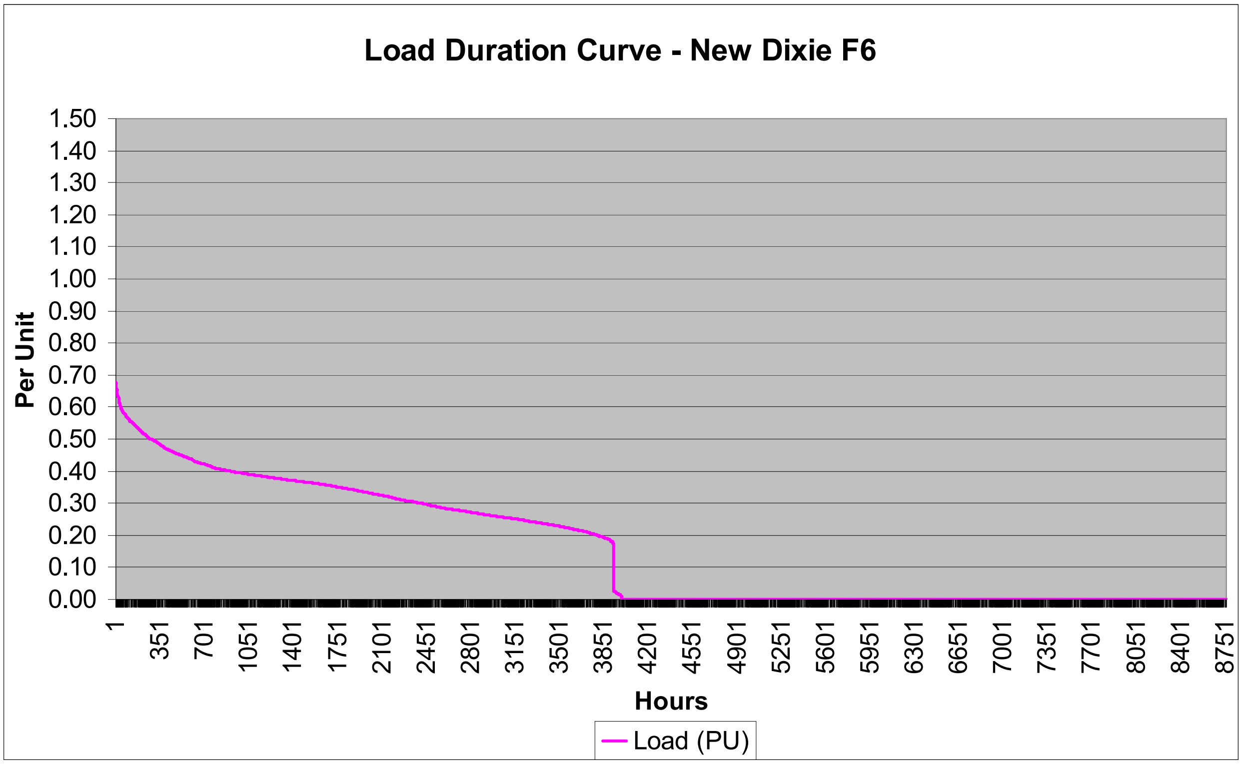
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - New Dixie F6
Per Unit
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1.30
1.20
1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
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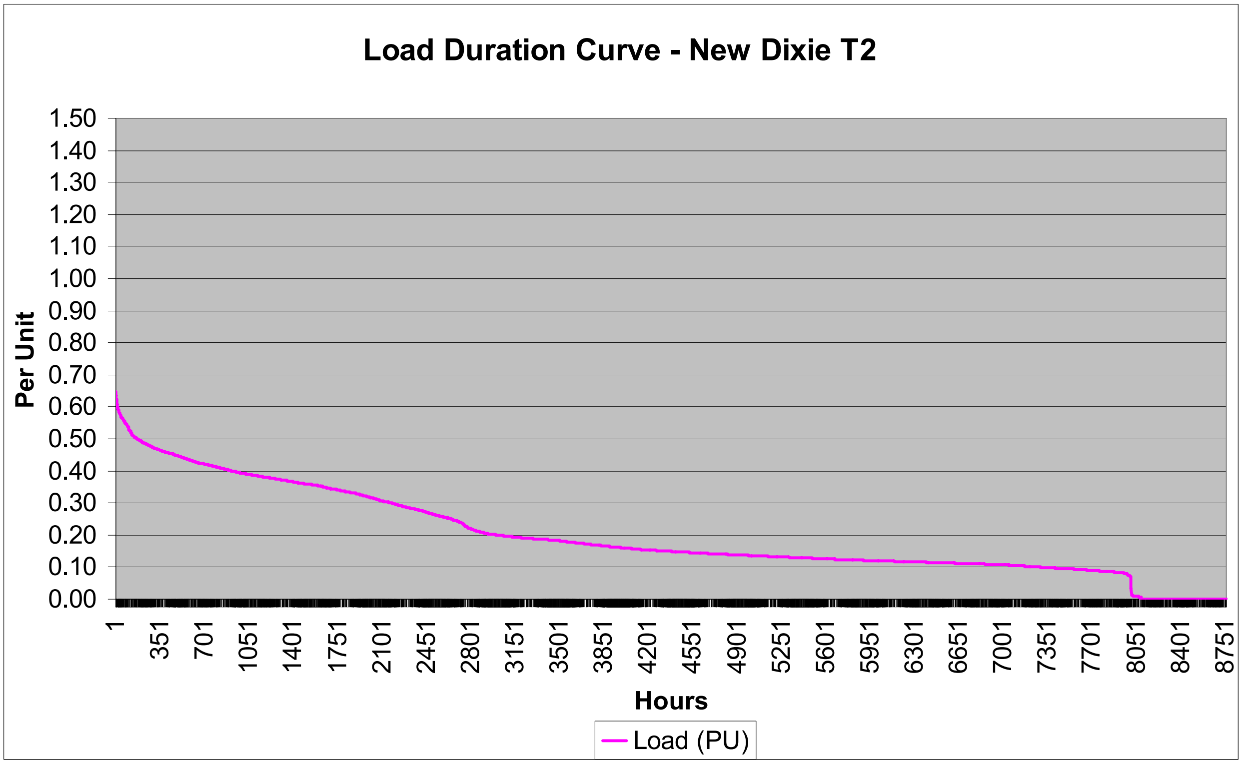
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - New Dixie T2
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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6651
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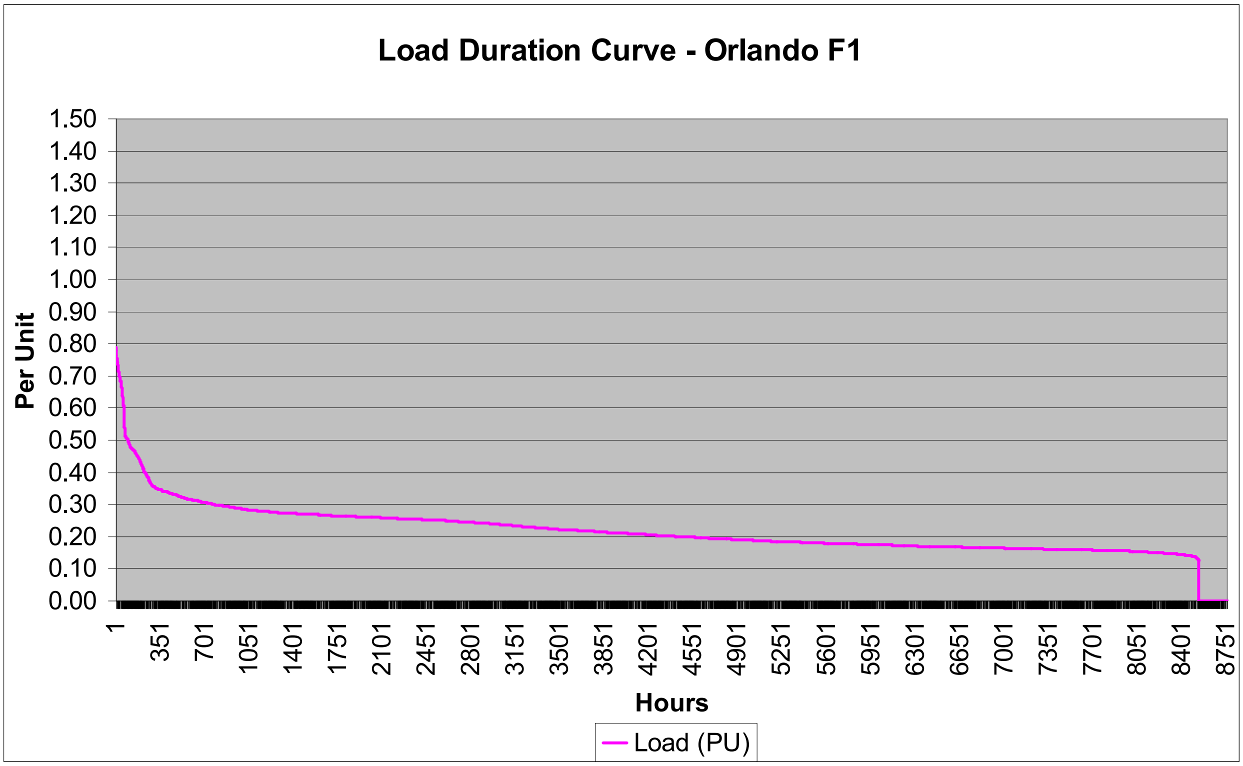
7351
7701
8051
8401
8751
Hours
Load (PU)

Orlando MS


Load Duration Curve - Orlando F1
Per Unit
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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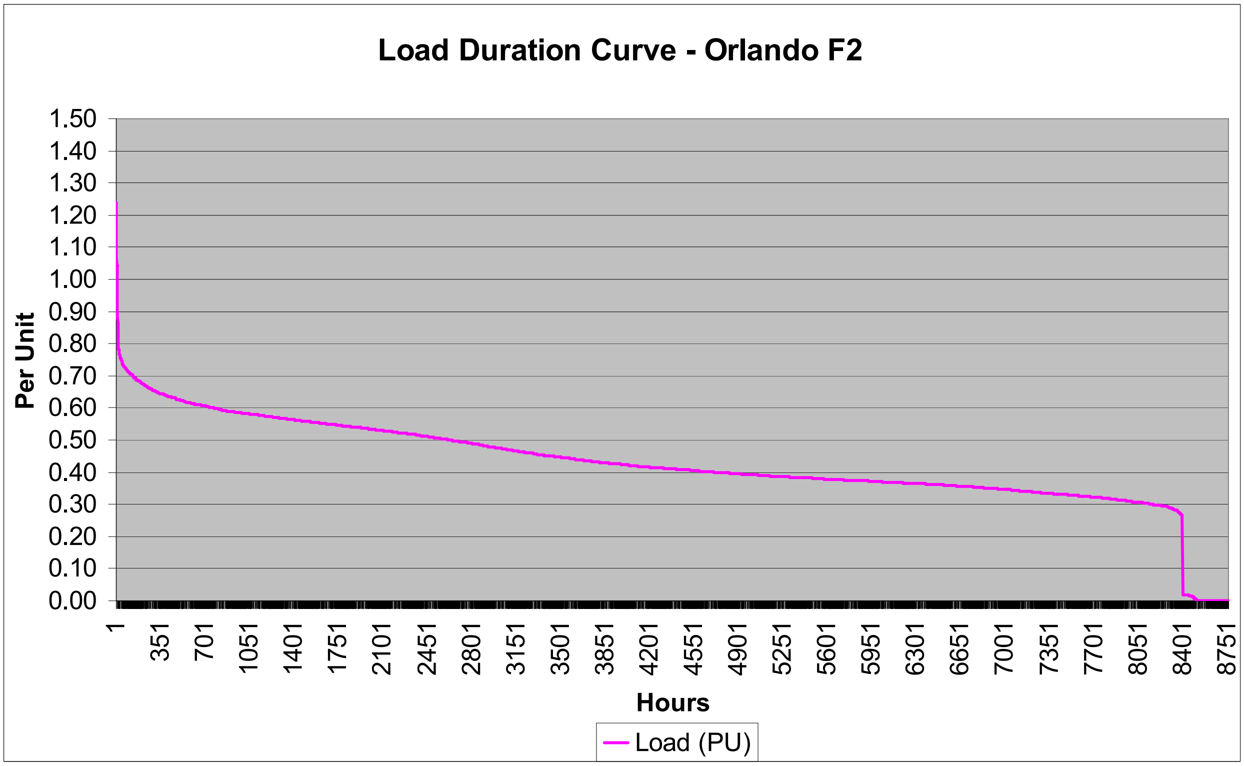
8401
8751
Hours
Load (PU)


Load Duration Curve - Orlando F2
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
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4201
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6651
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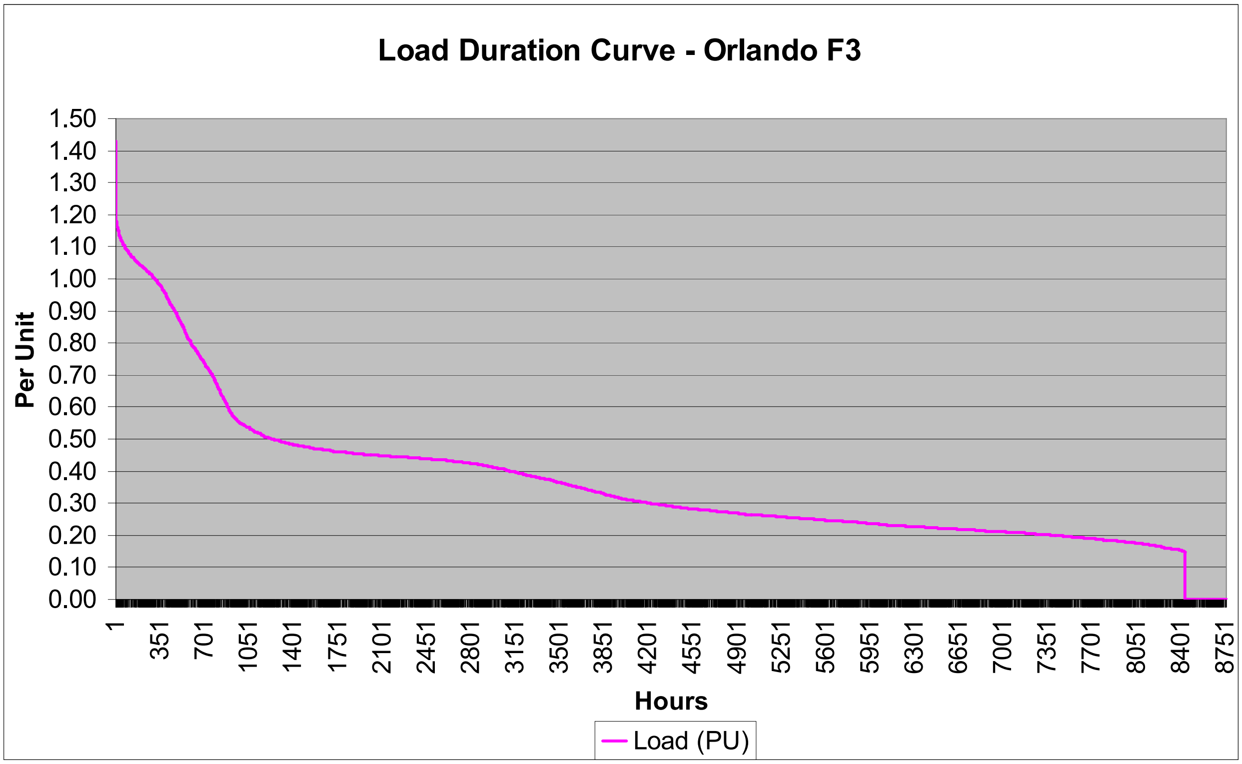
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Orlando F3
Per Unit
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0.50
0.40
0.30
0.20
0.10
0.00
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701
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1401
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4201
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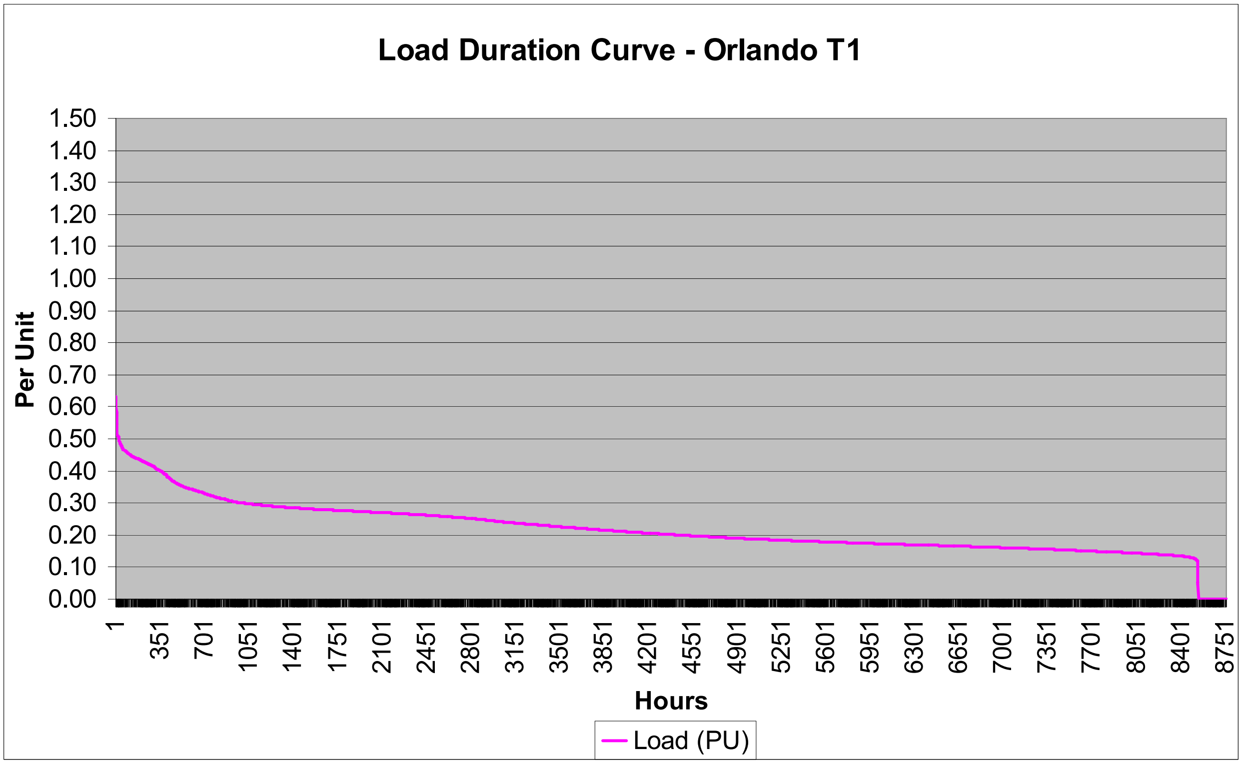
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Orlando T1
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
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1401
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3851
4201
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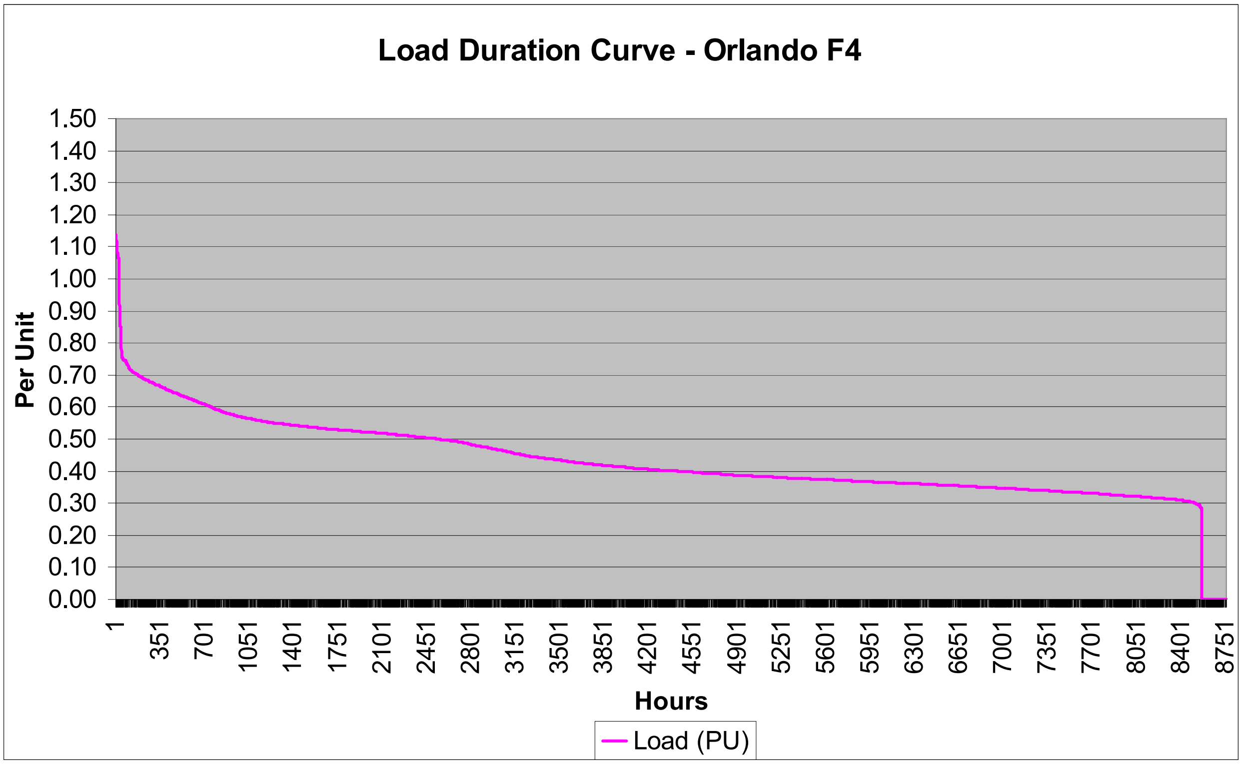
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Orlando F4
Per Unit
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1.00
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0.80
0.70
0.60
0.50
0.40
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0.20
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0.00
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351
701
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1401
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4201
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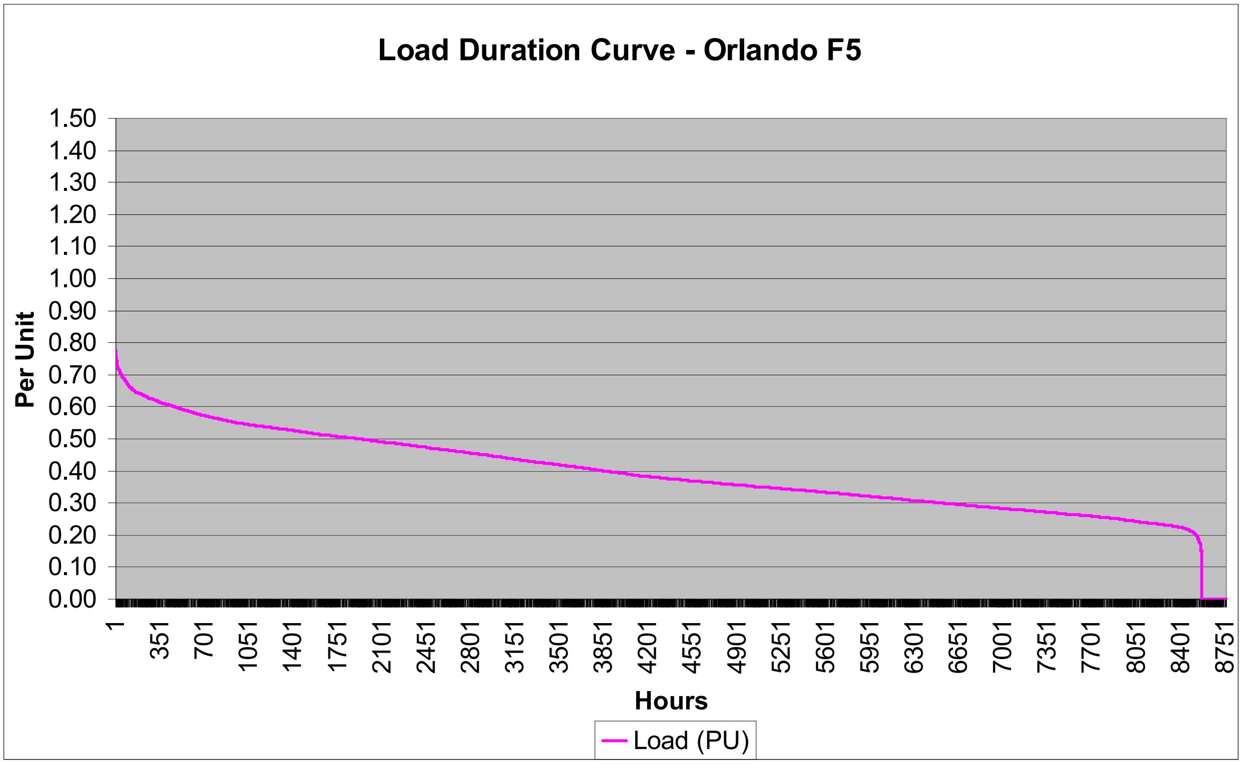
8751
Hours
Load (PU)


Load Duration Curve - Orlando F5
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
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1401
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4201
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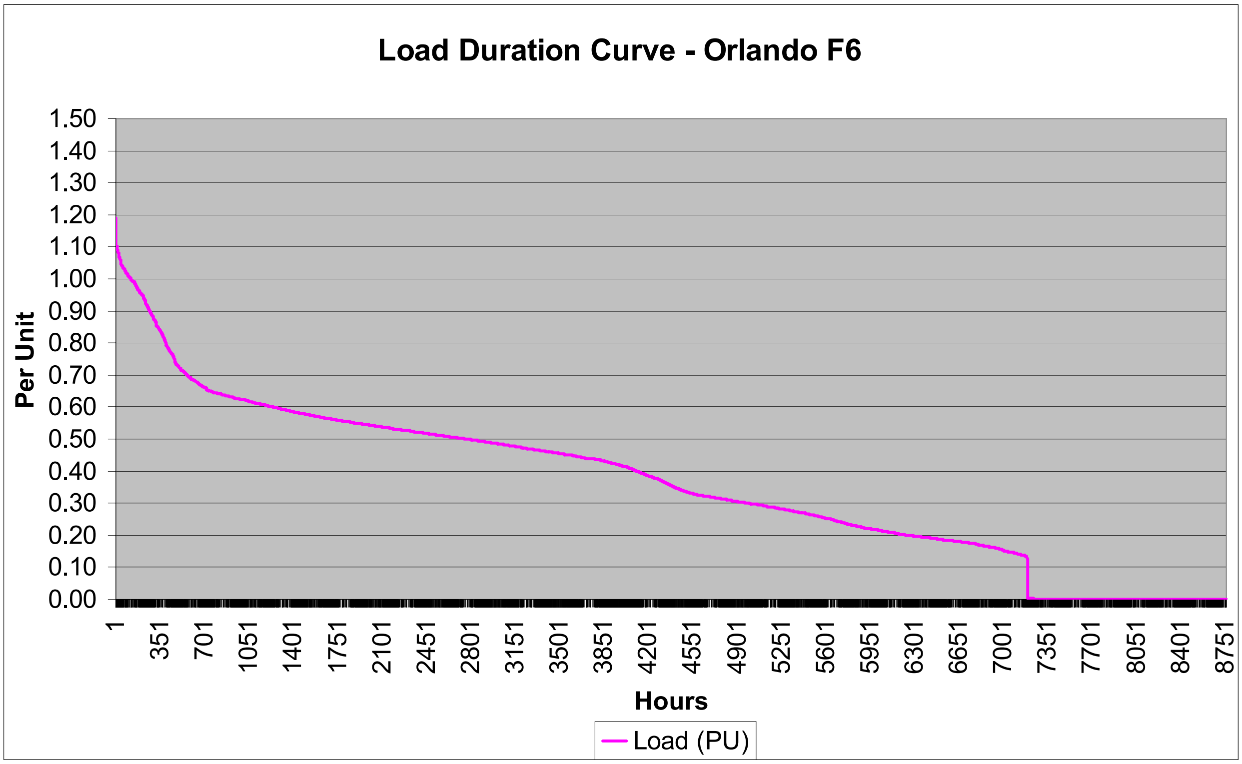
8751
Hours
Load (PU)


Load Duration Curve - Orlando F6
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0.40
0.30
0.20
0.10
0.00
Per Unit
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351
701
1051
1401
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4201
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8051
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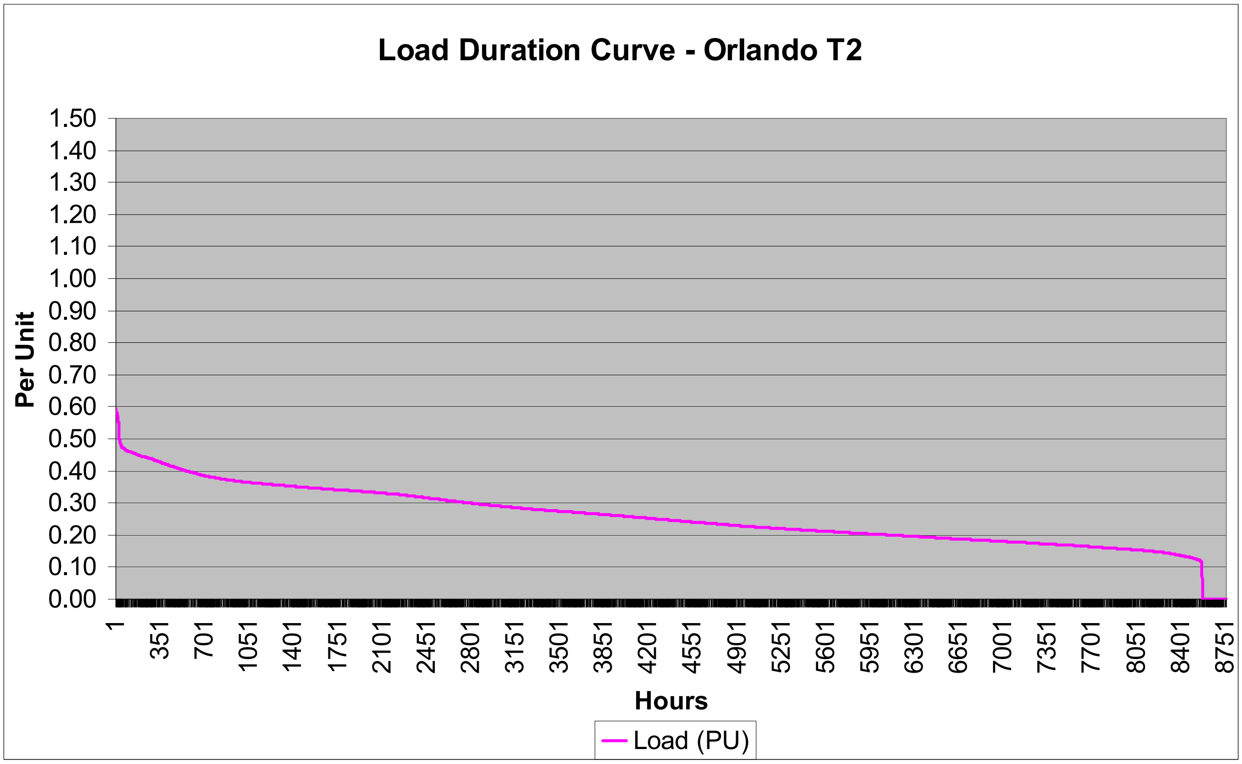
8751
Hours
Load (PU)


Load Duration Curve - Orlando T2
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
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351
701
1051
1401
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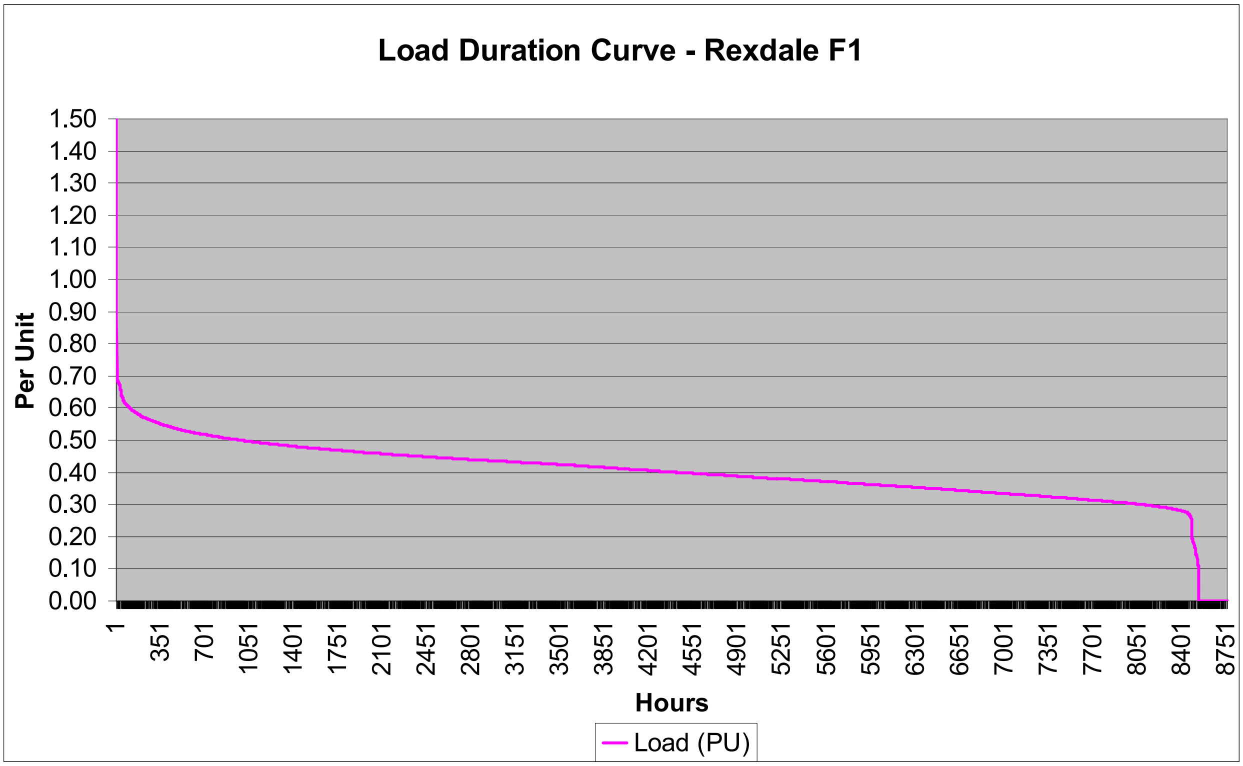
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Rexdale MS



Load Duration Curve - Rexdale F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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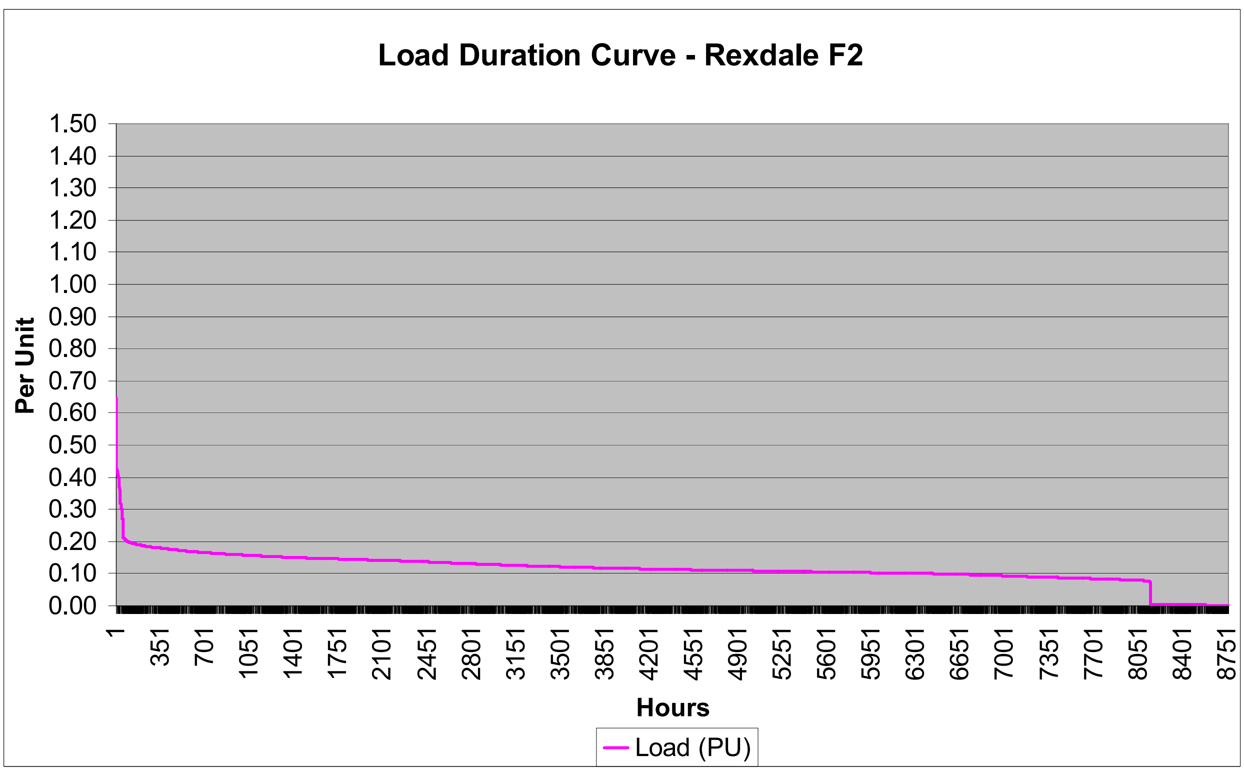
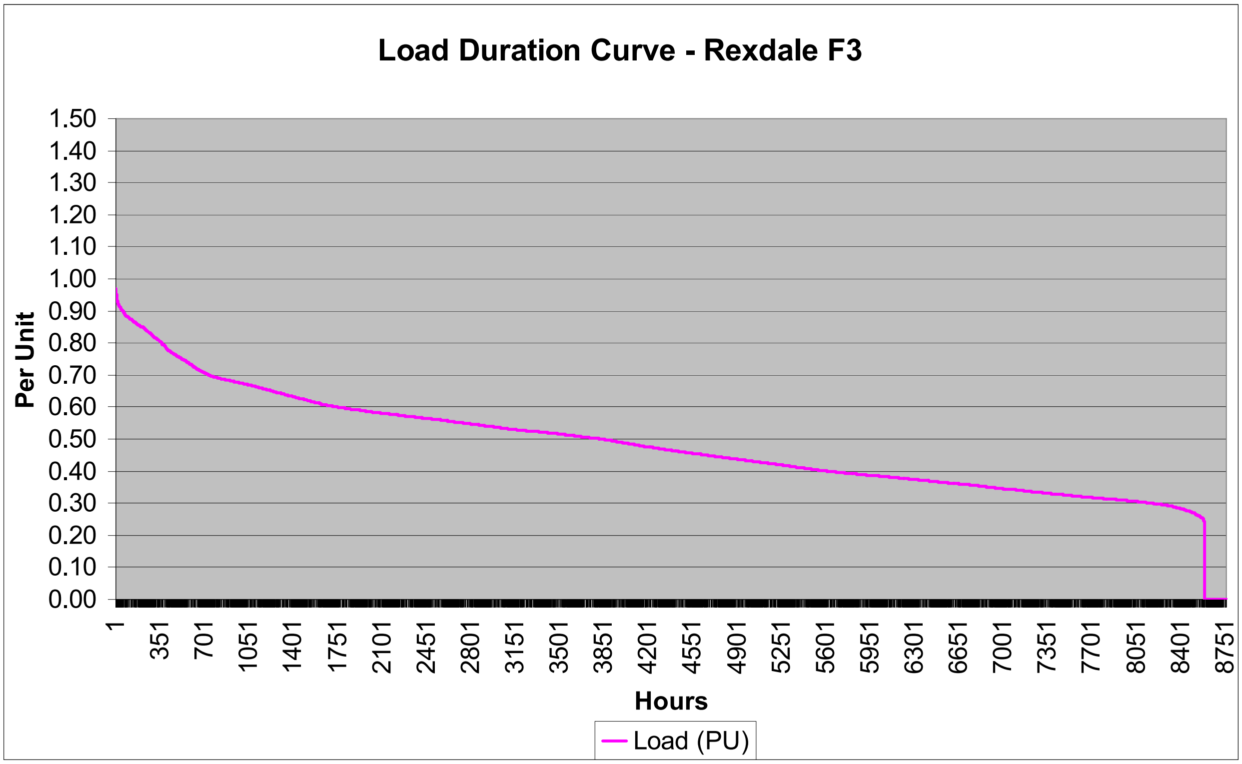
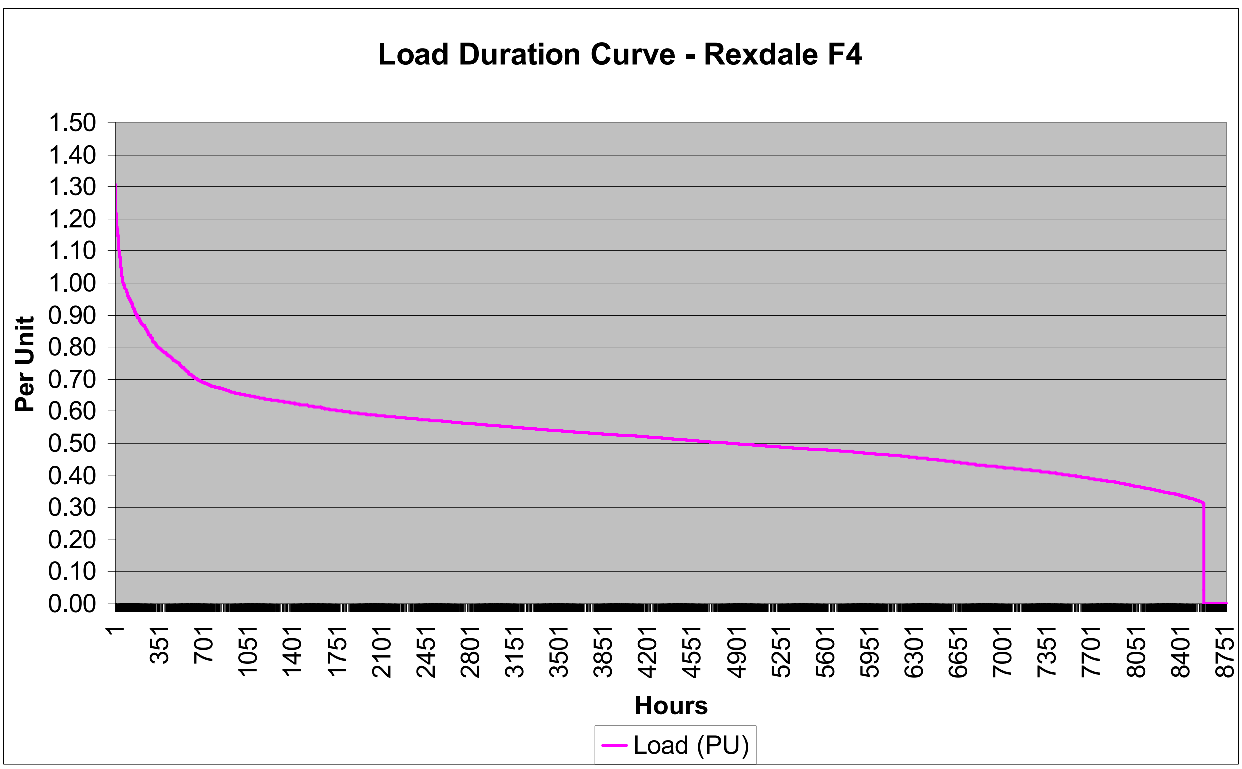
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Rexdale F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rexdale F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rexdale F4
Per Unit
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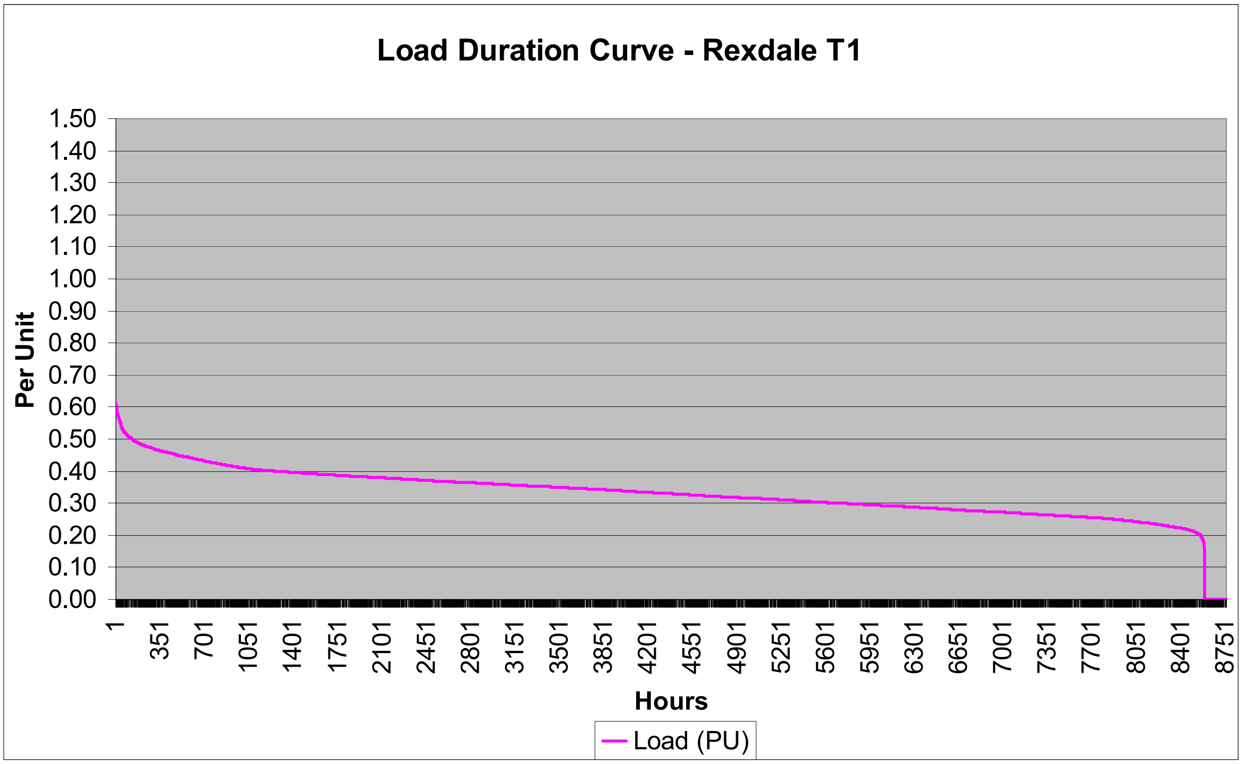
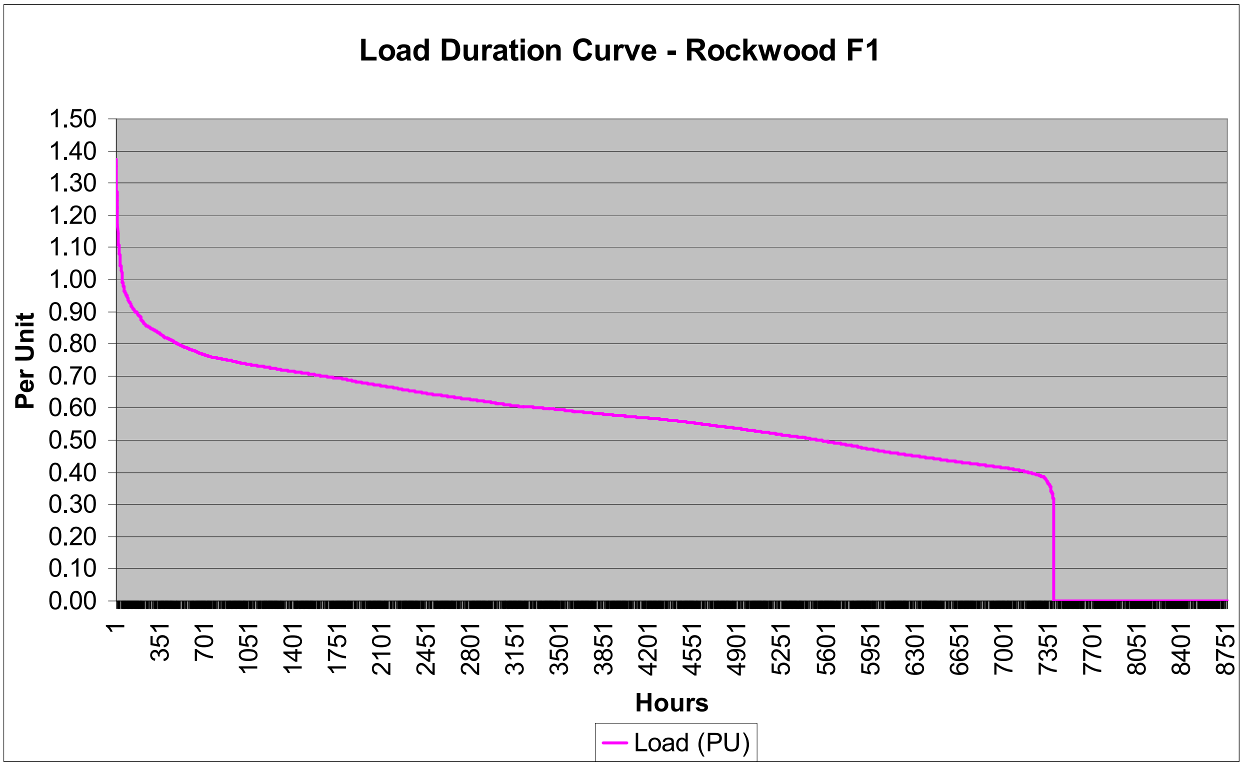
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

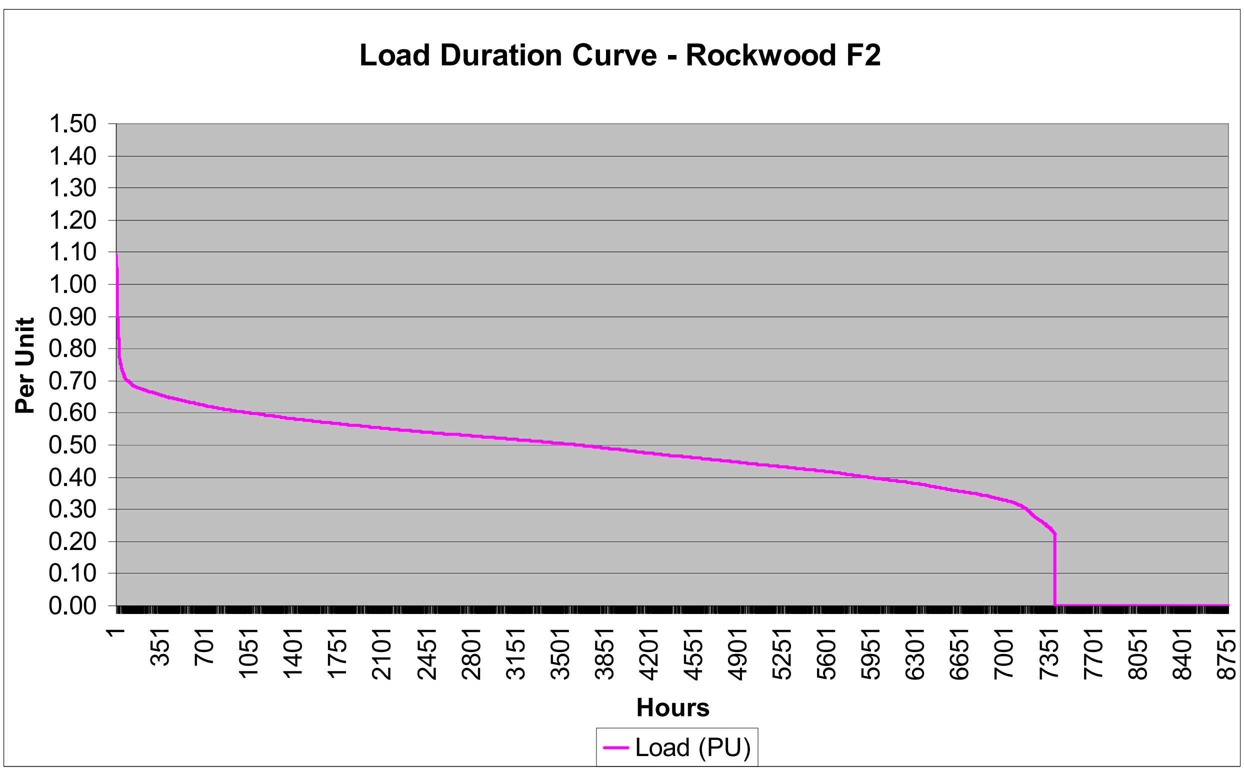


Load Duration Curve - Rexdale T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

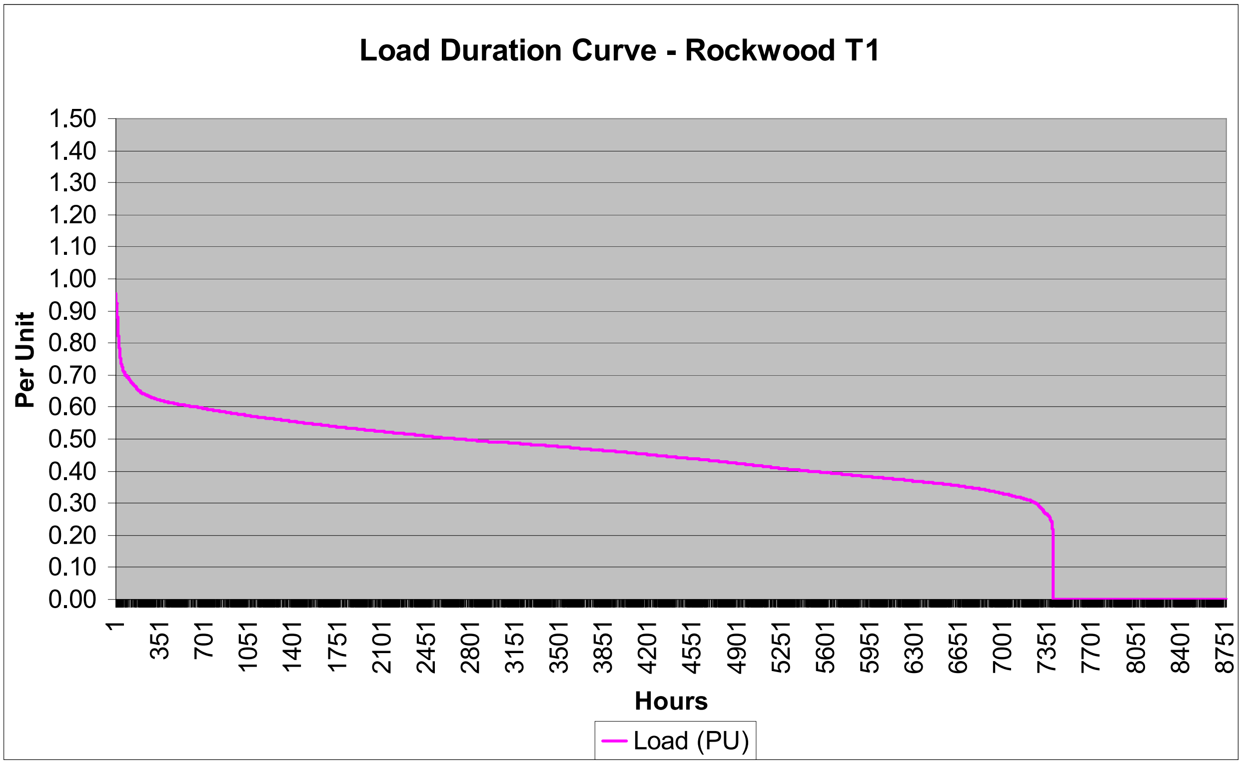
Rockwood MS



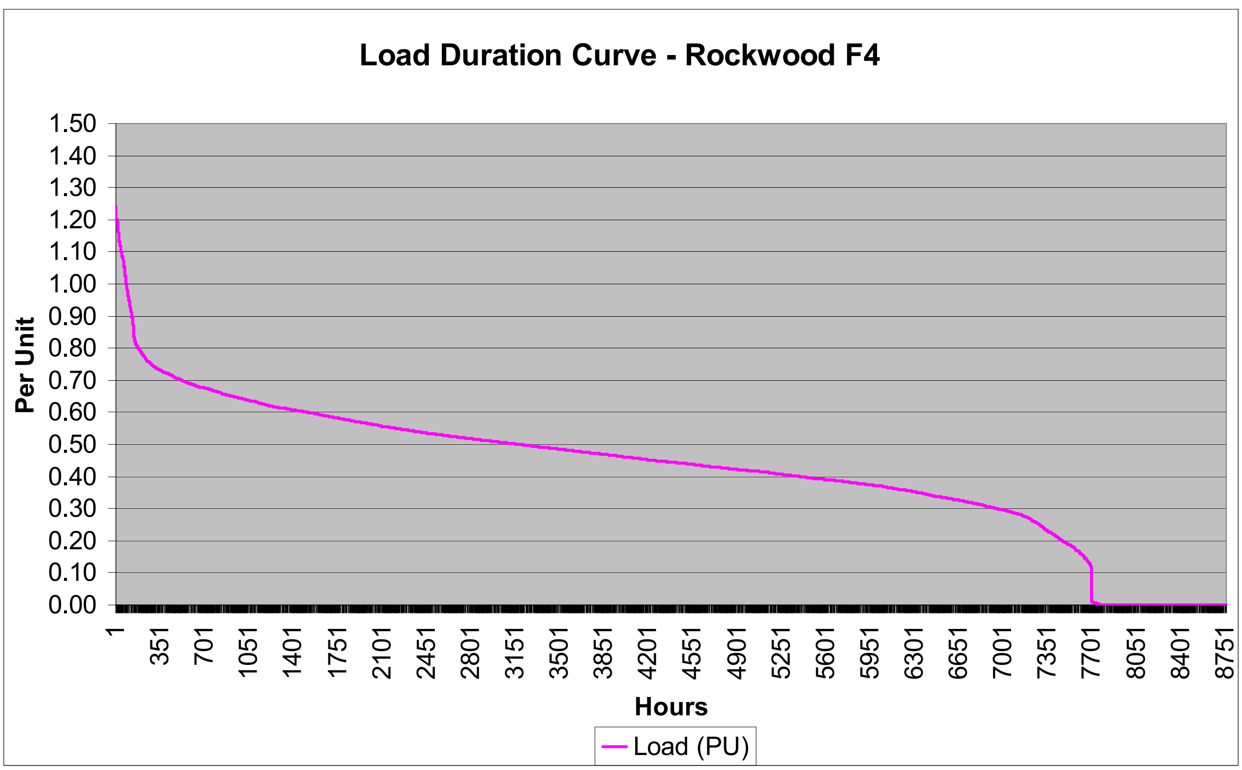
Load Duration Curve - Rockwood F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



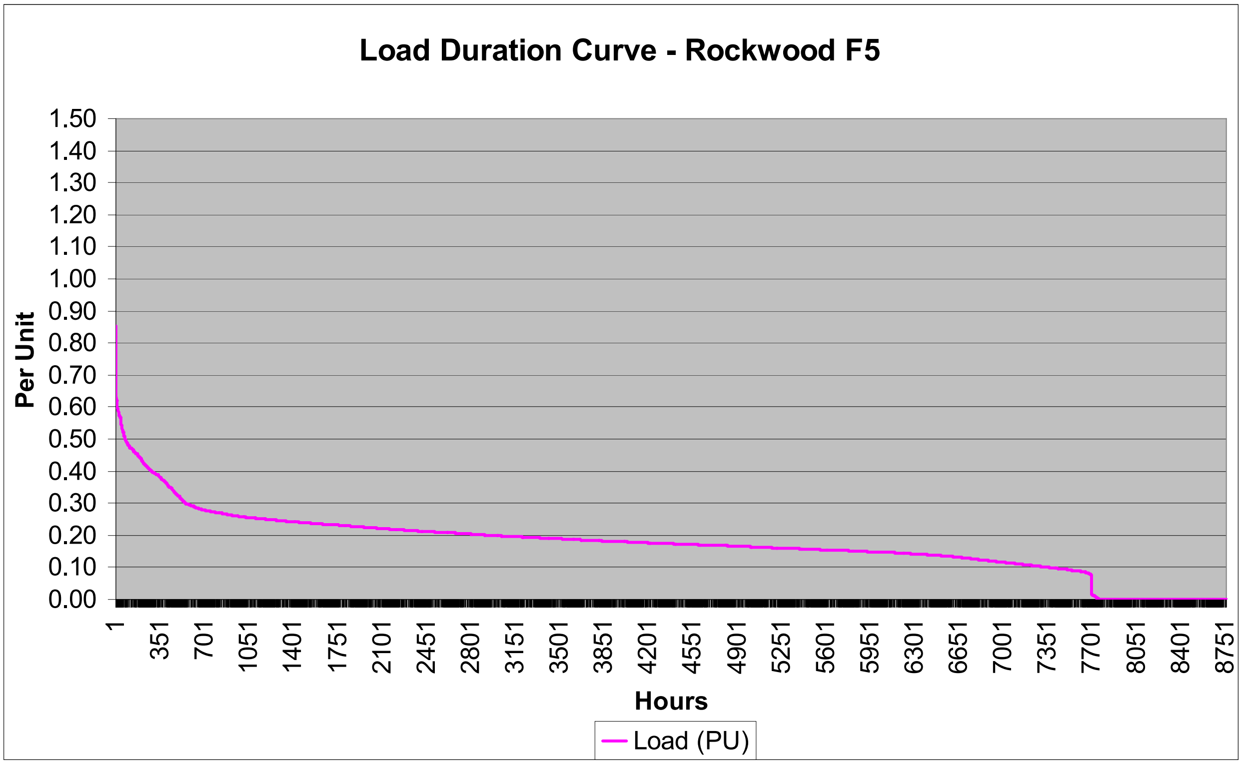
Load Duration Curve - Rockwood F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

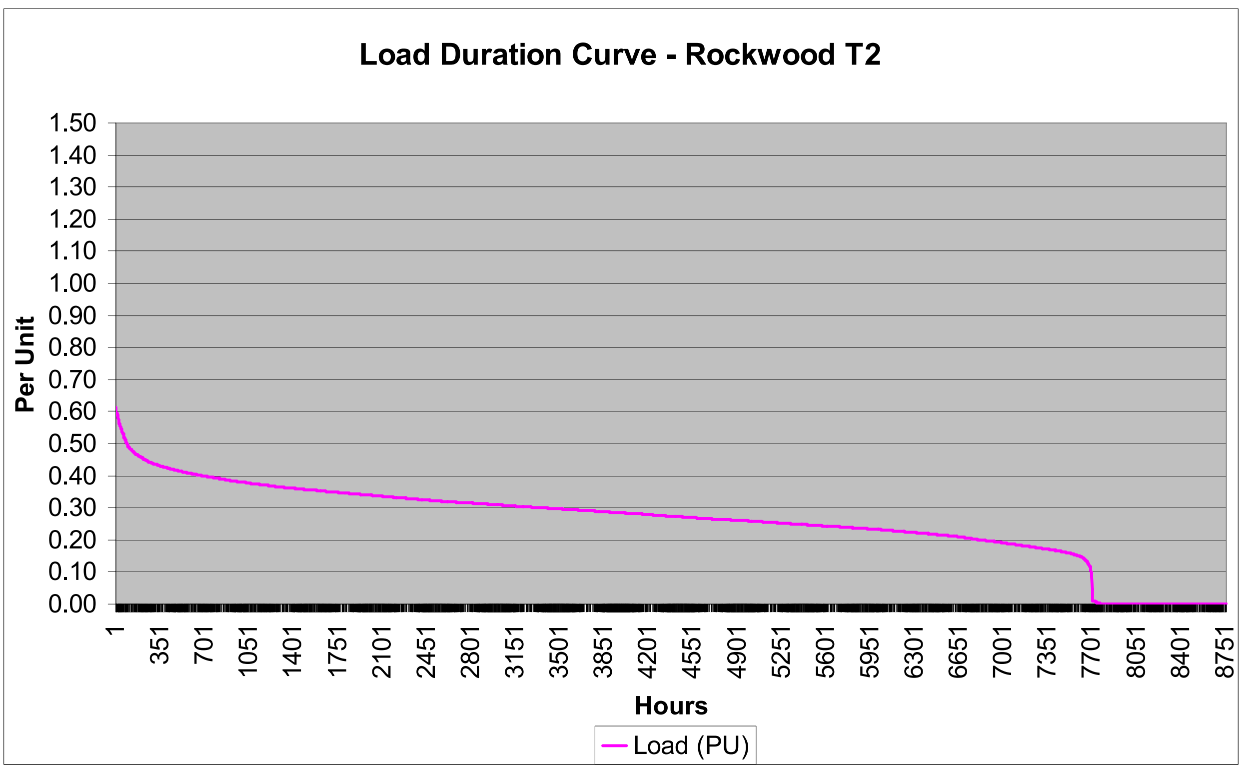


Load Duration Curve - Rockwood T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

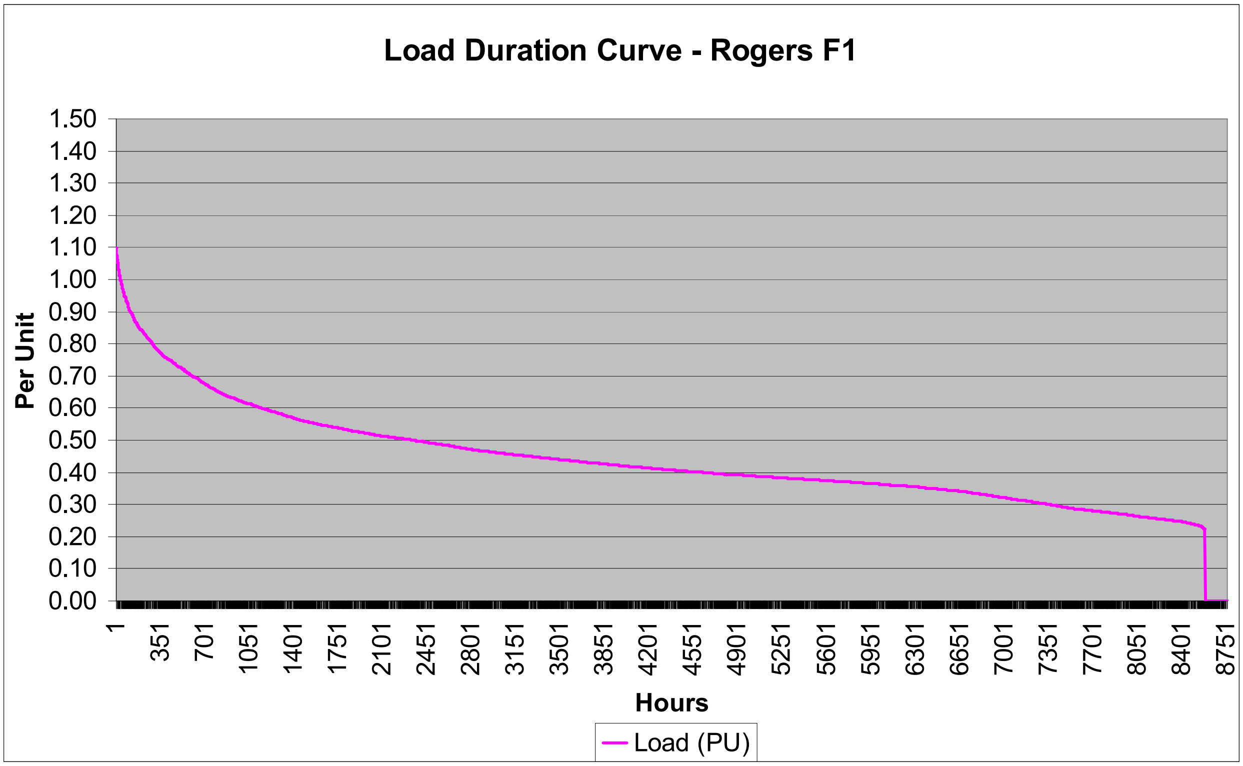


Load Duration Curve - Rockwood F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rockwood F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rockwood T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Rogers MS


Load Duration Curve - Rogers F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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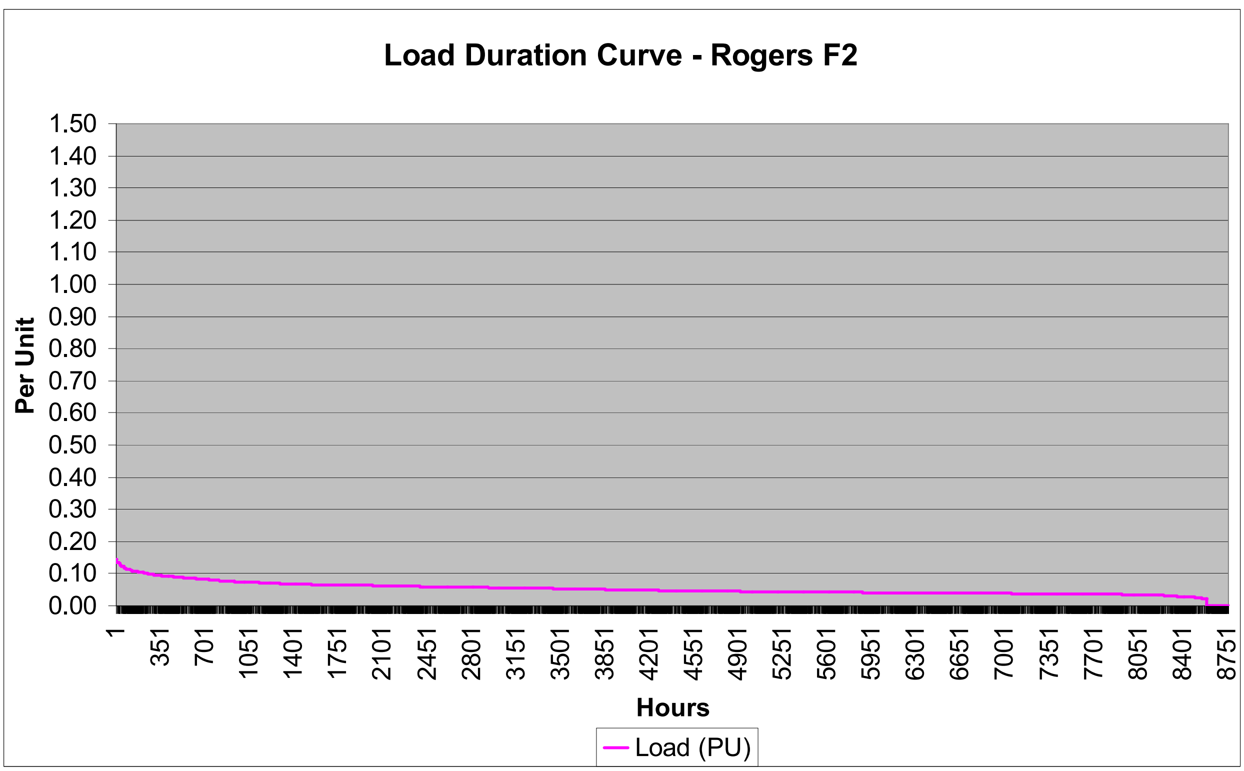
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers F2
Per Unit
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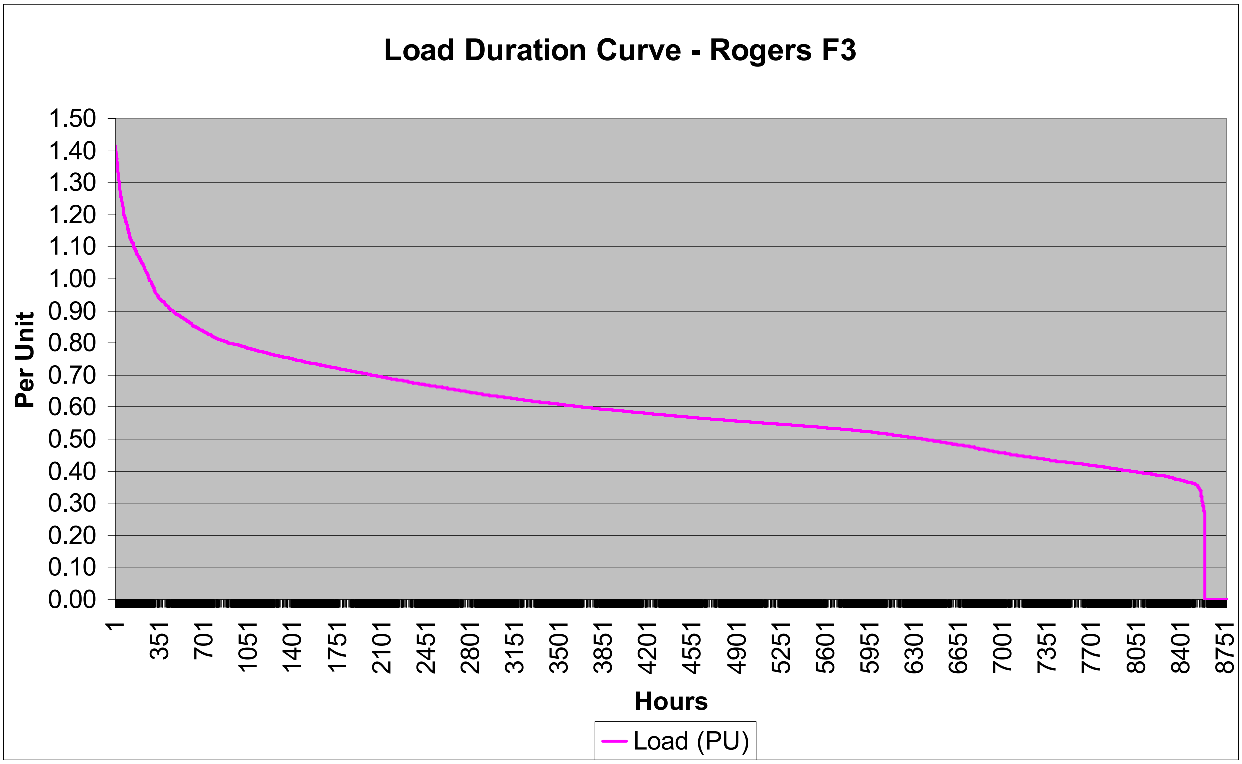
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers F3
Per Unit
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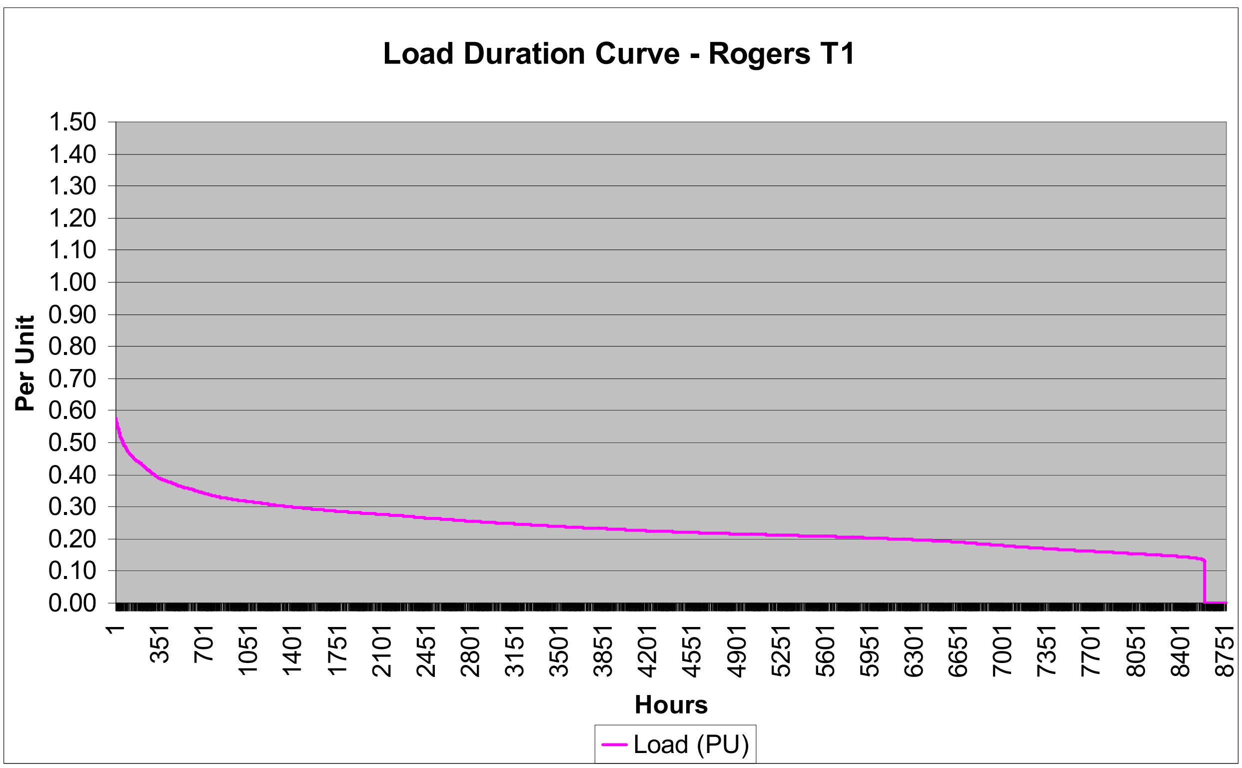
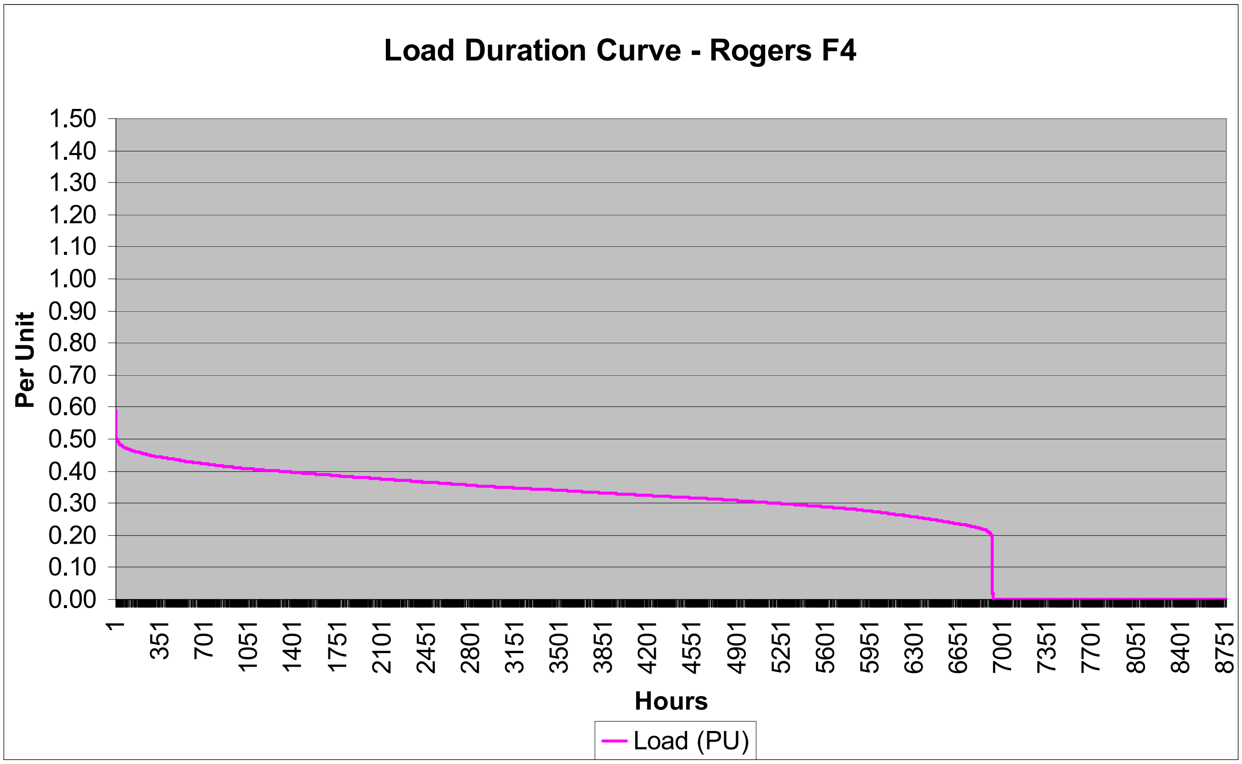
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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6301
6651
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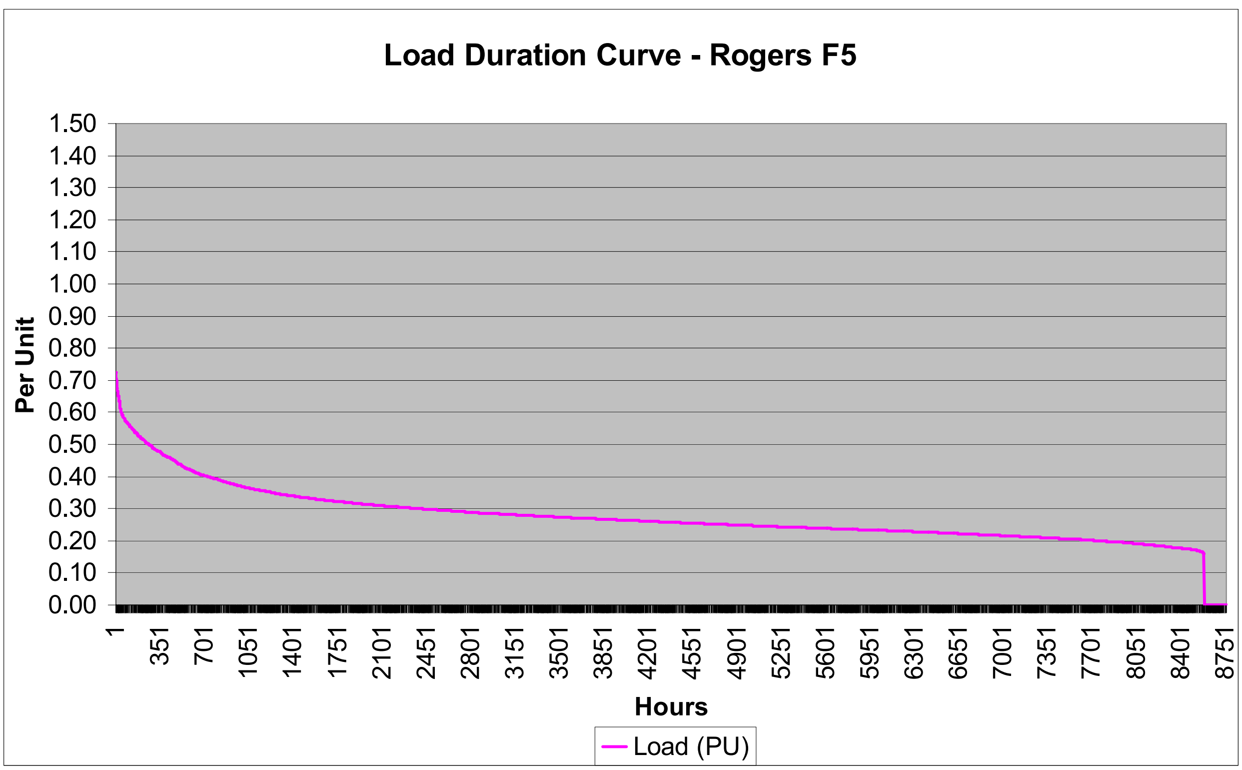
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers F5
Per Unit
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1.30
1.20
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5601
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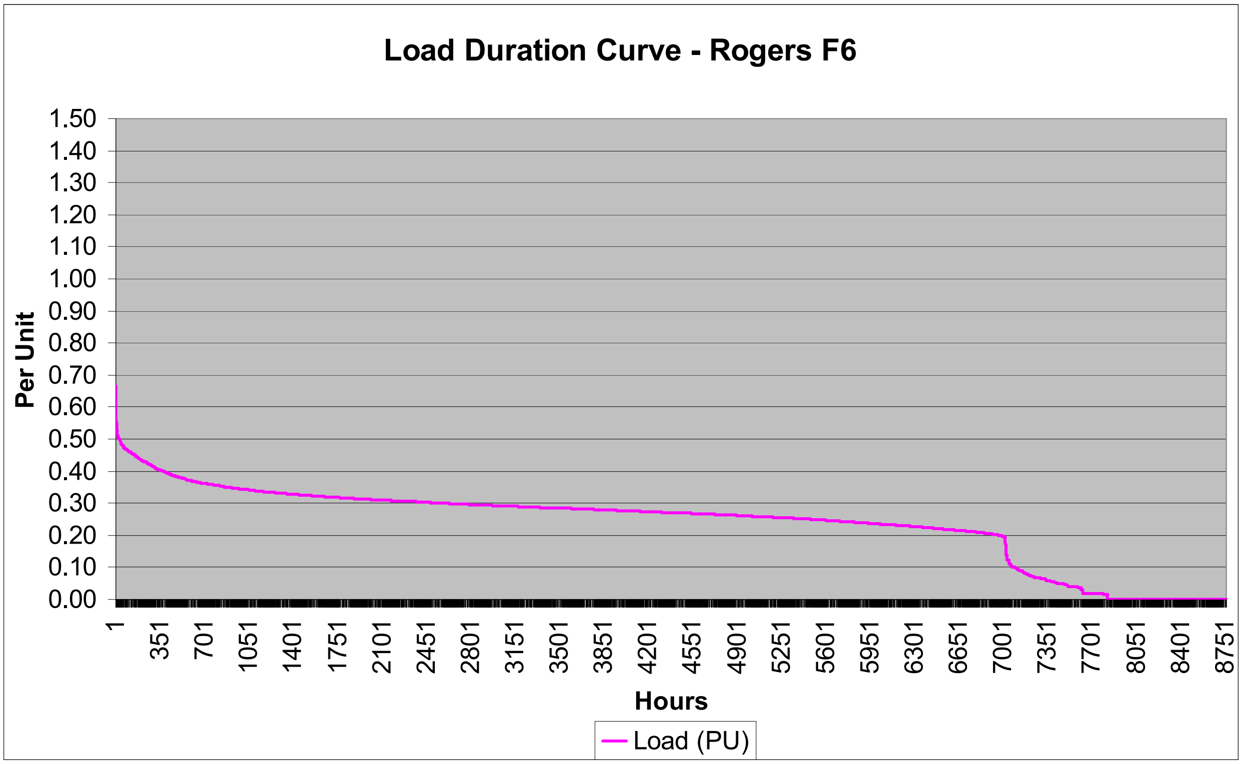
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers F6
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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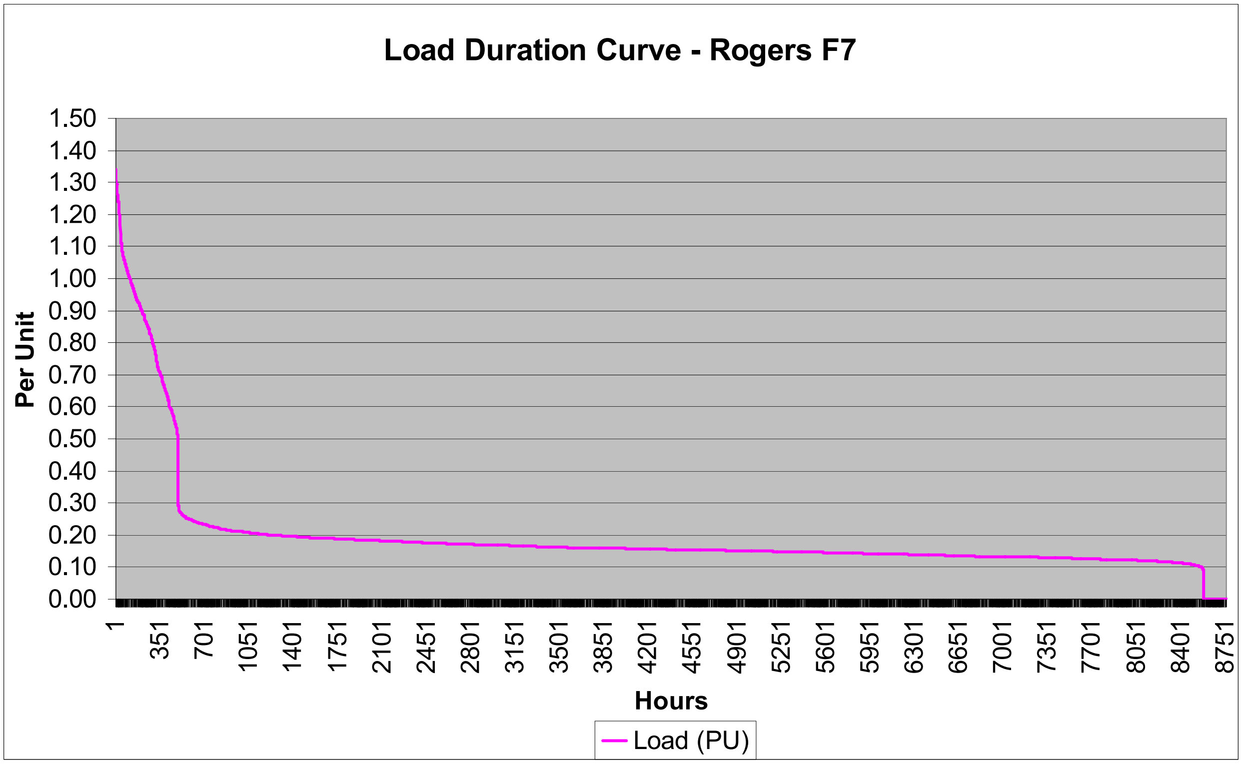
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rogers F7
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
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3851
4201
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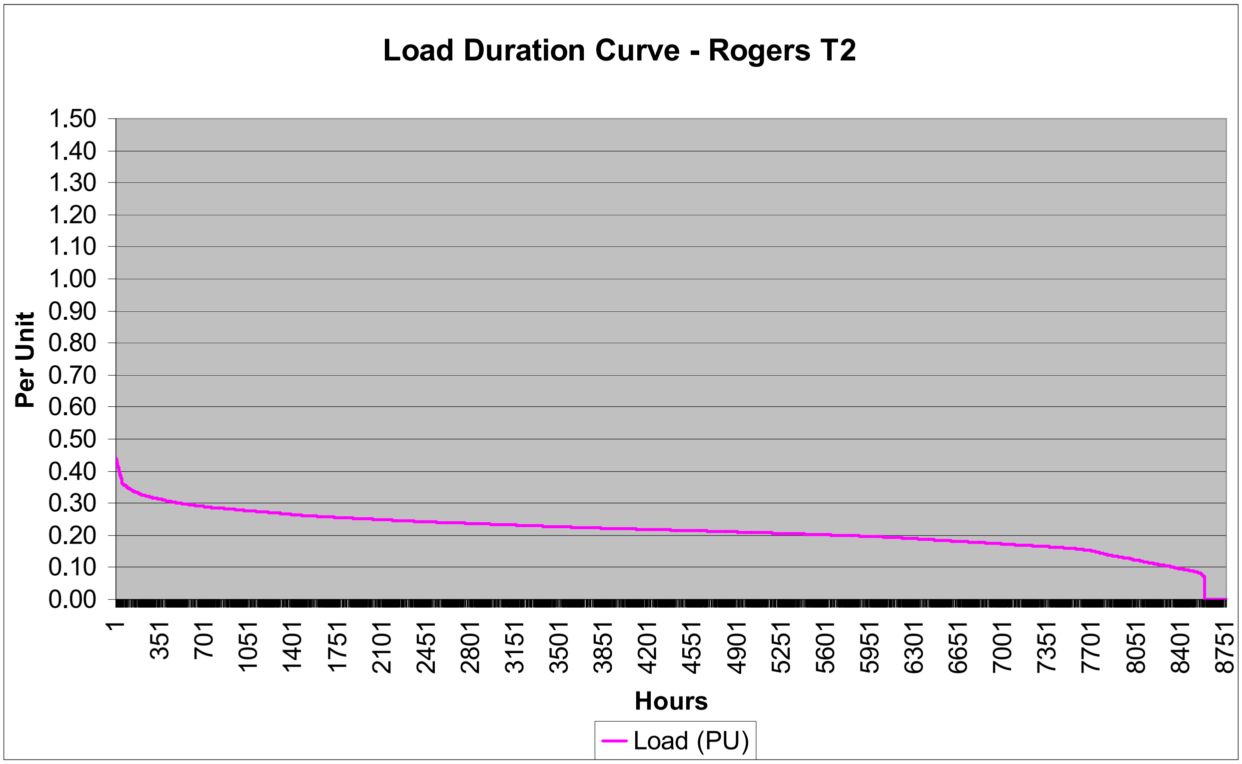
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Rogers T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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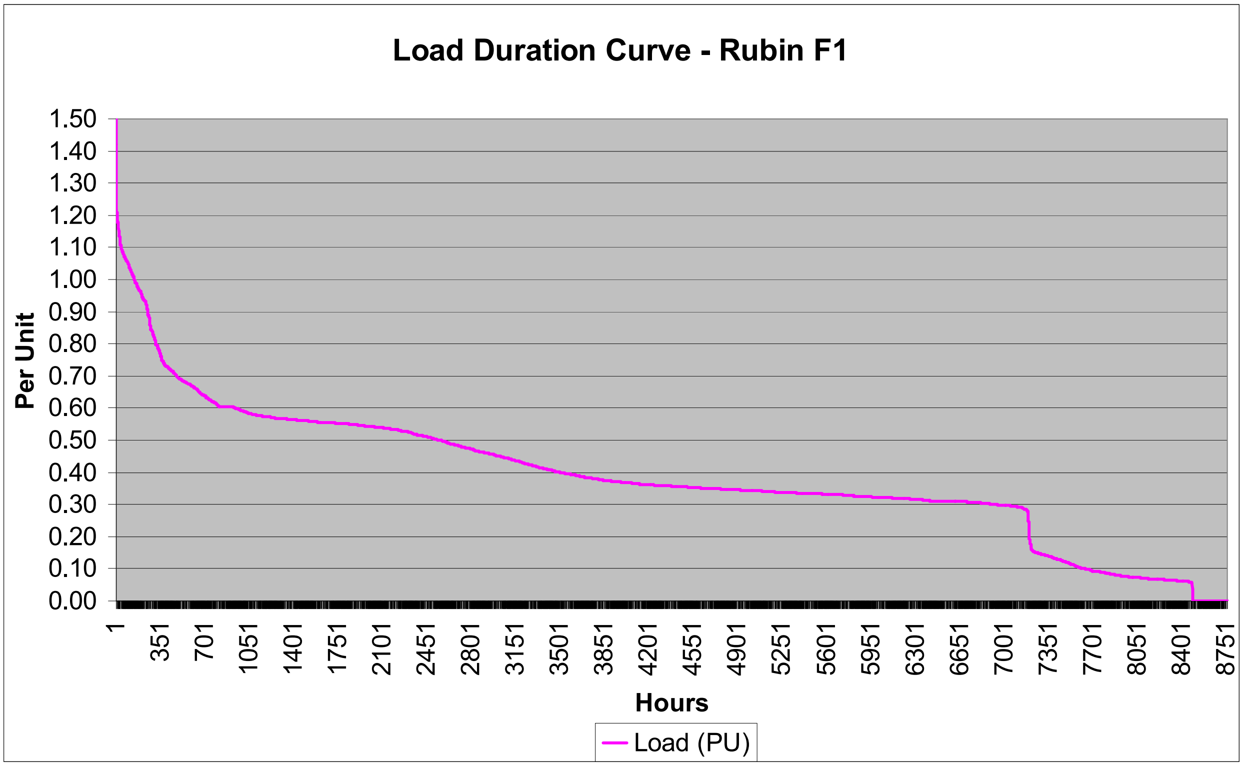
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Rubin MS


Load Duration Curve - Rubin F1
Per Unit
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1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6651
7001
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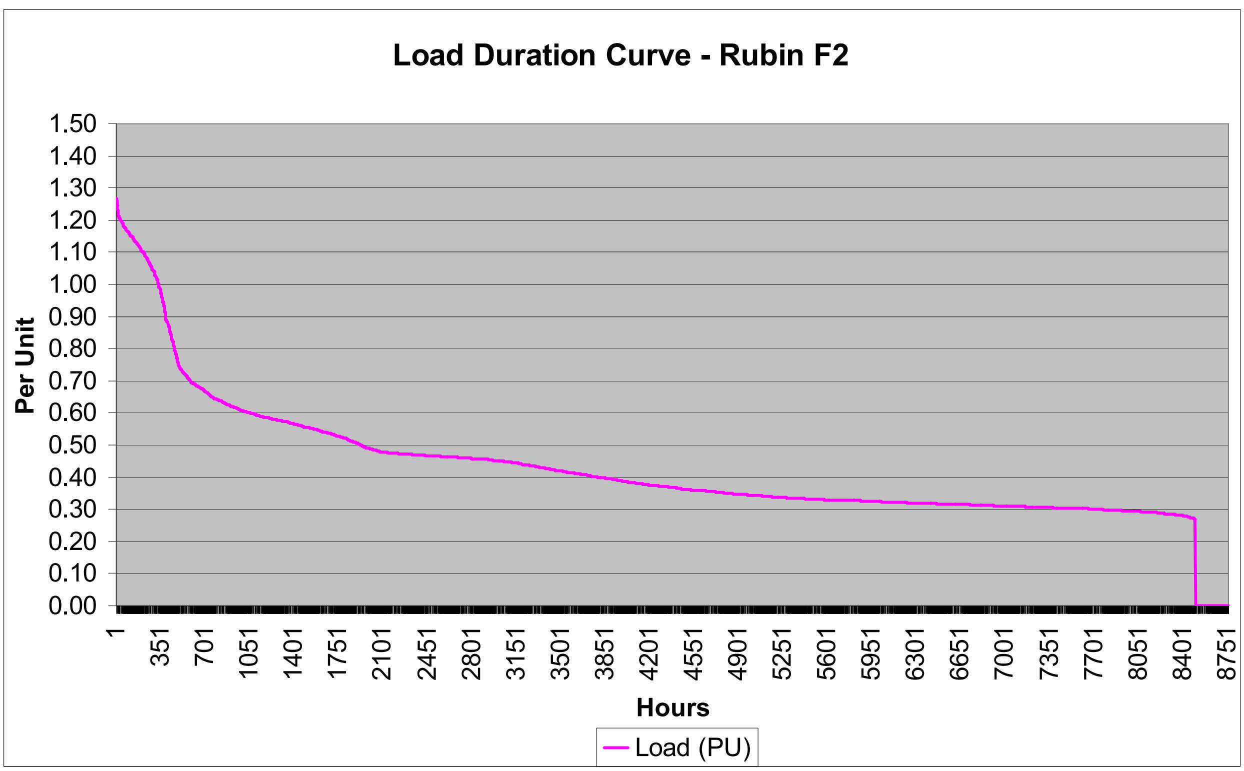
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rubin F2
Per Unit
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1.30
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
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3851
4201
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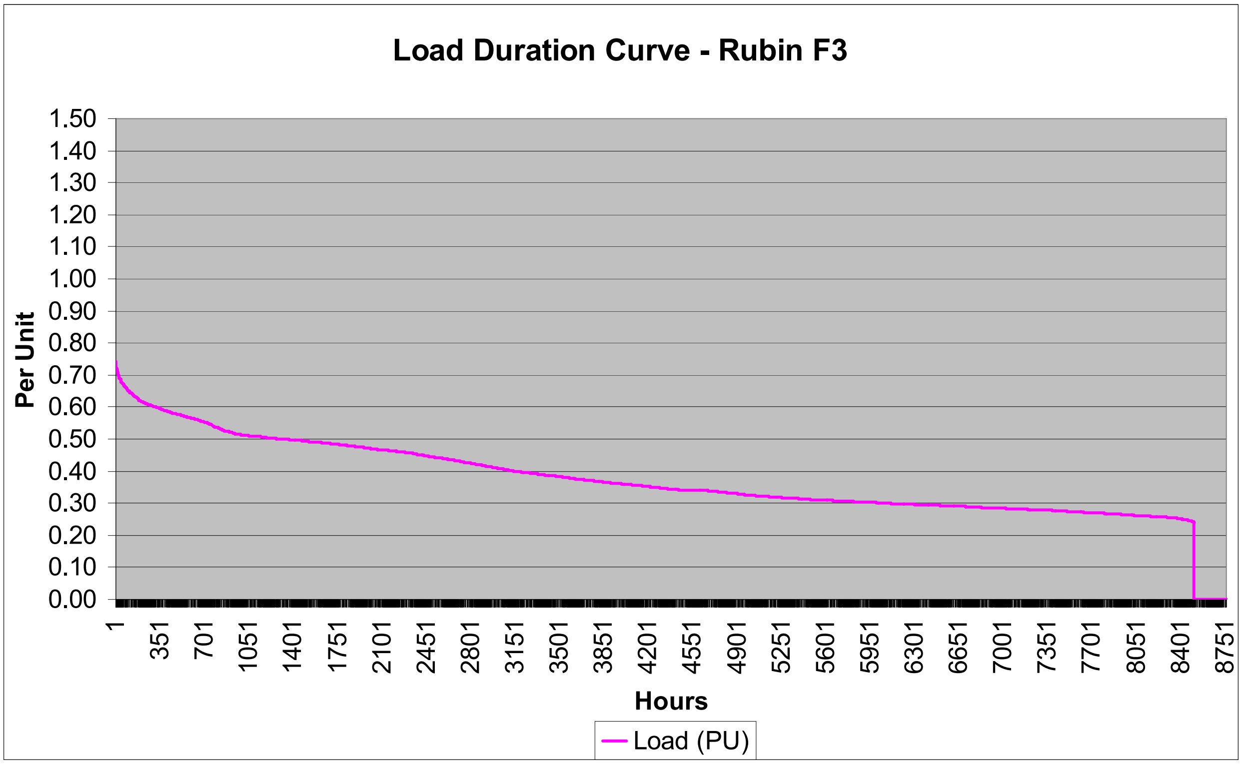
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rubin F3
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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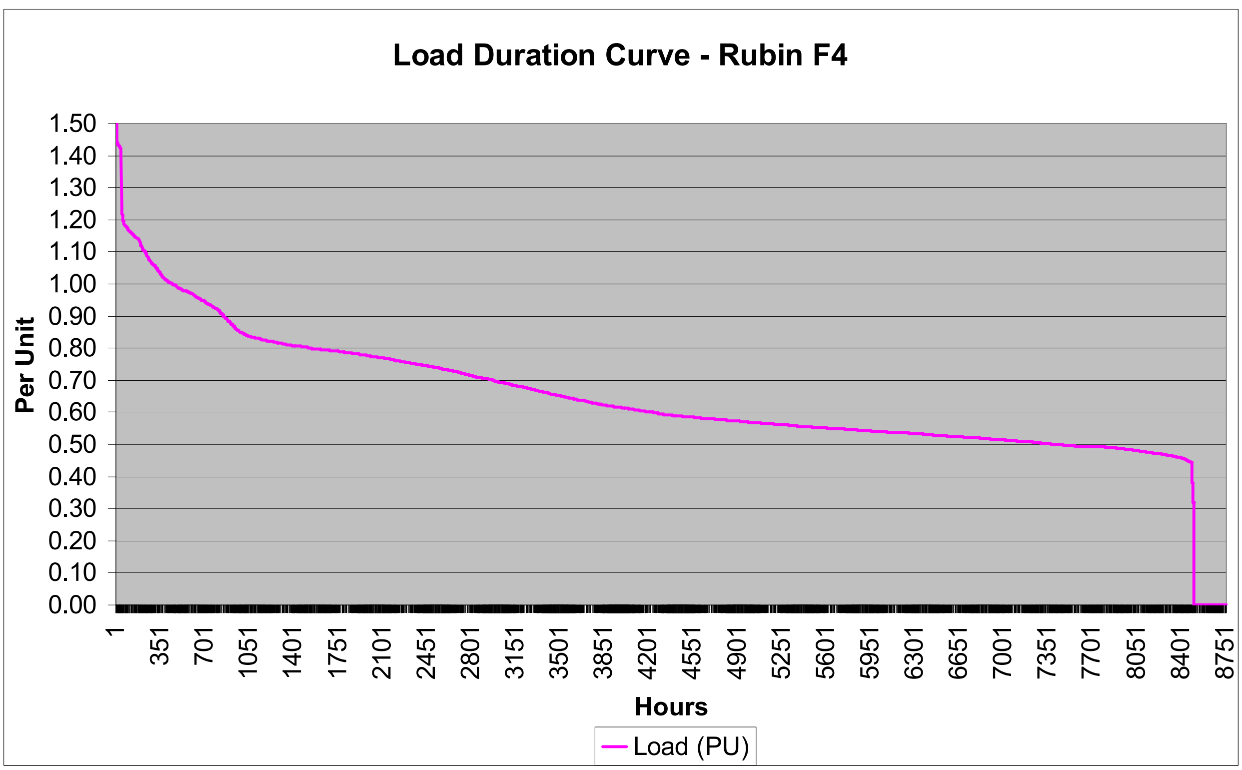
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Rubin F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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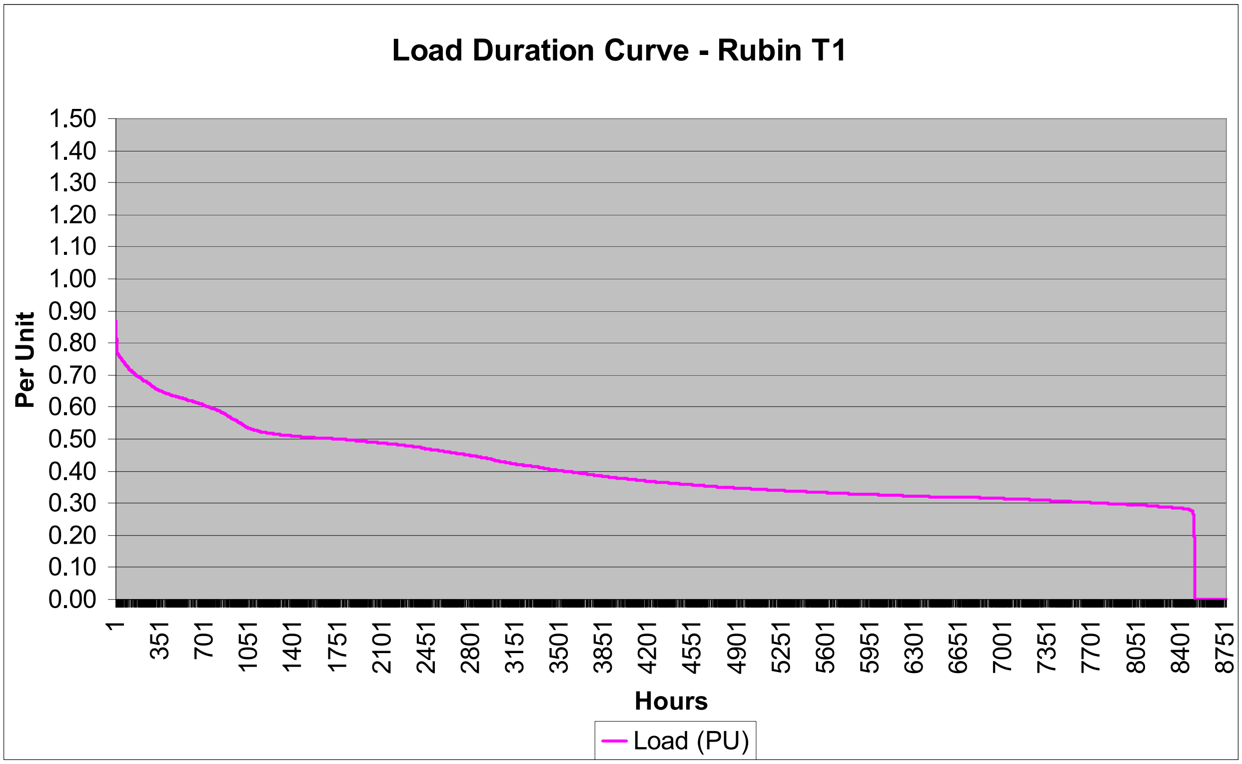
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Rubin T1
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
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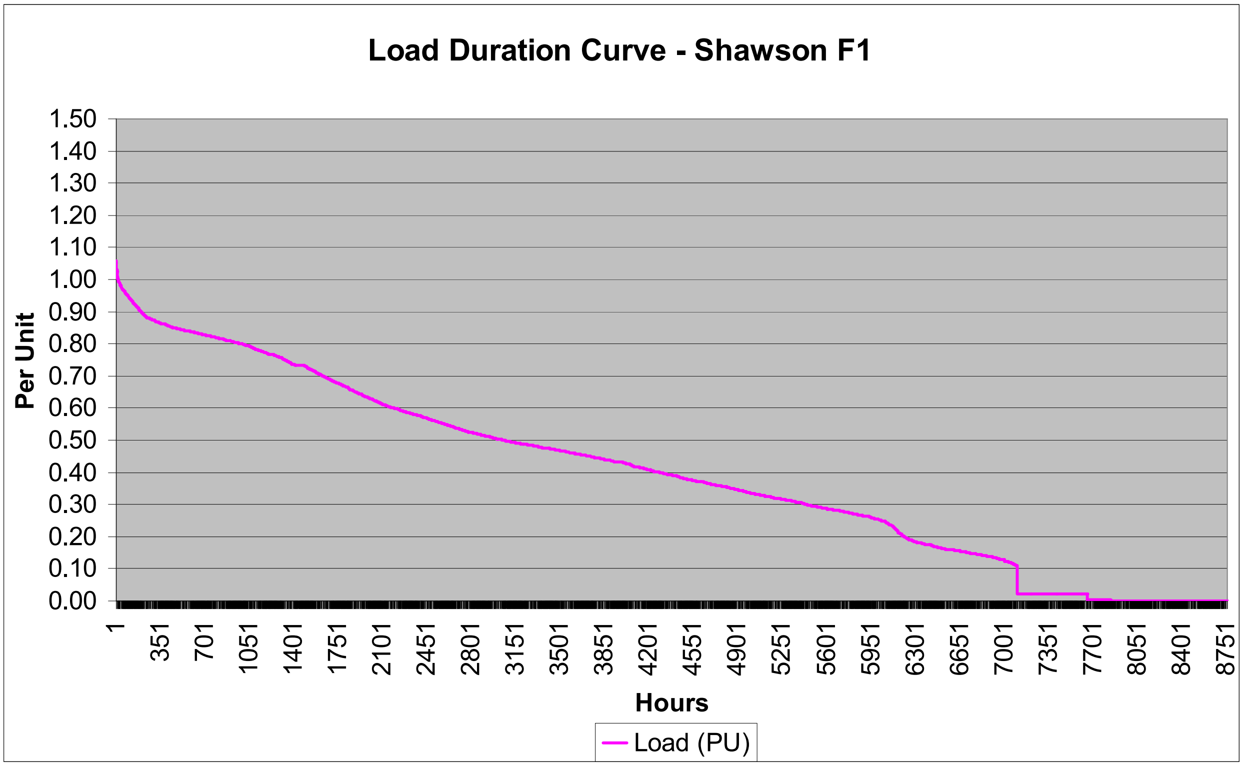
8401
8751
Hours
Load (PU)

Shawson MS


Load Duration Curve - Shawson F1
Per Unit
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1.40
1.30
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
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0.00
1
351
701
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4201
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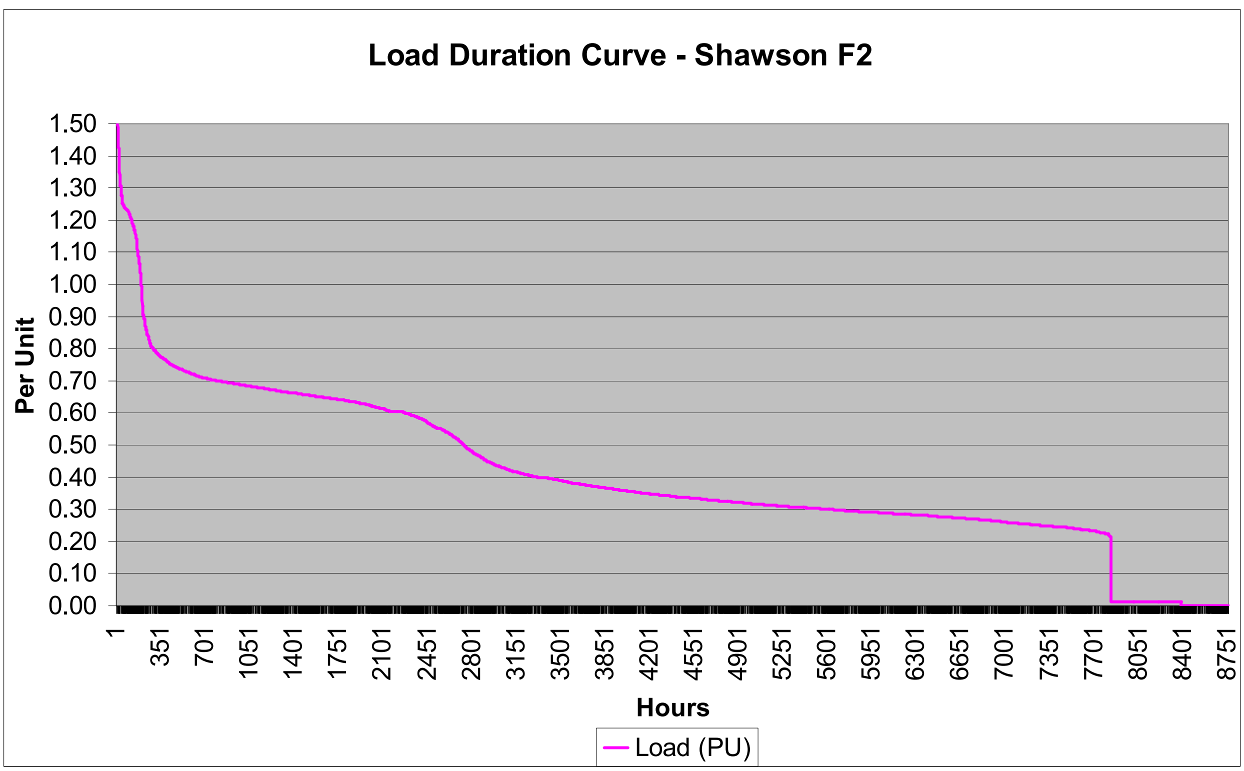
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson F2
Per Unit
1.50
1.40
1.30
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
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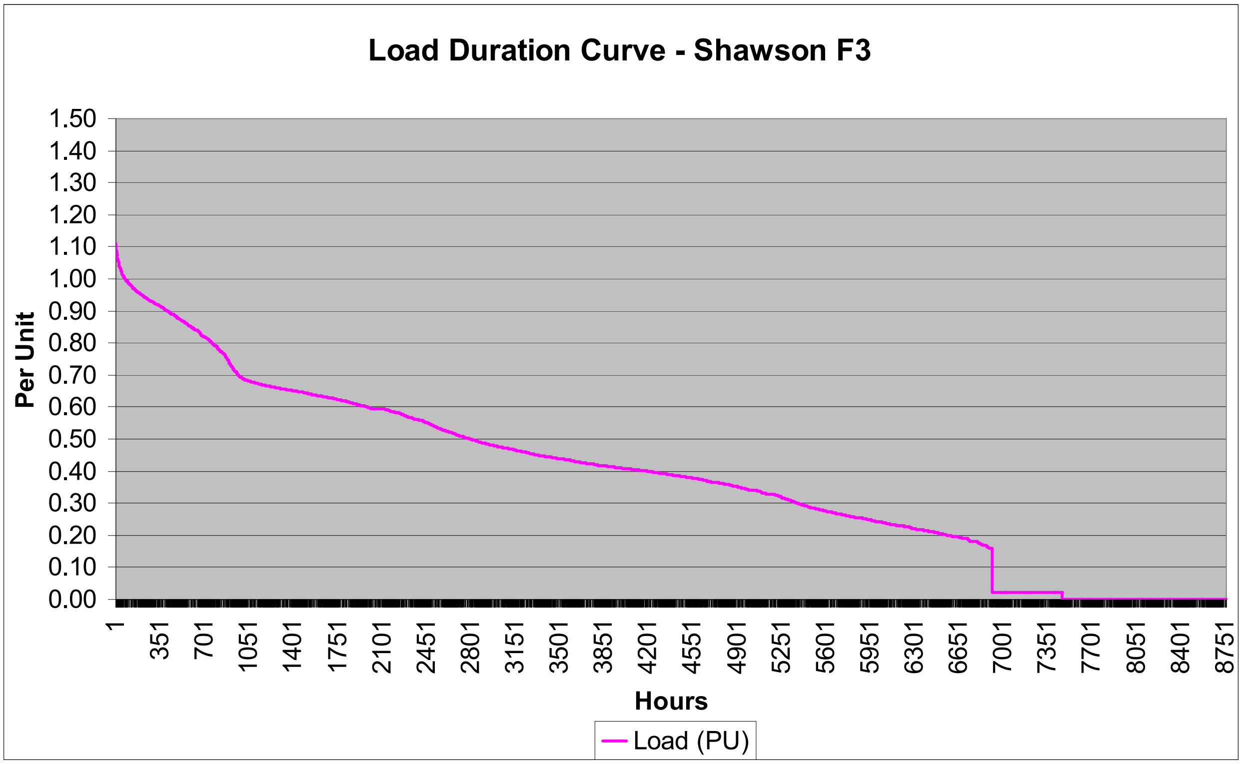
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson F3
Per Unit
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1.40
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
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701
1051
1401
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2101
2451
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3151
3501
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4201
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6651
7001
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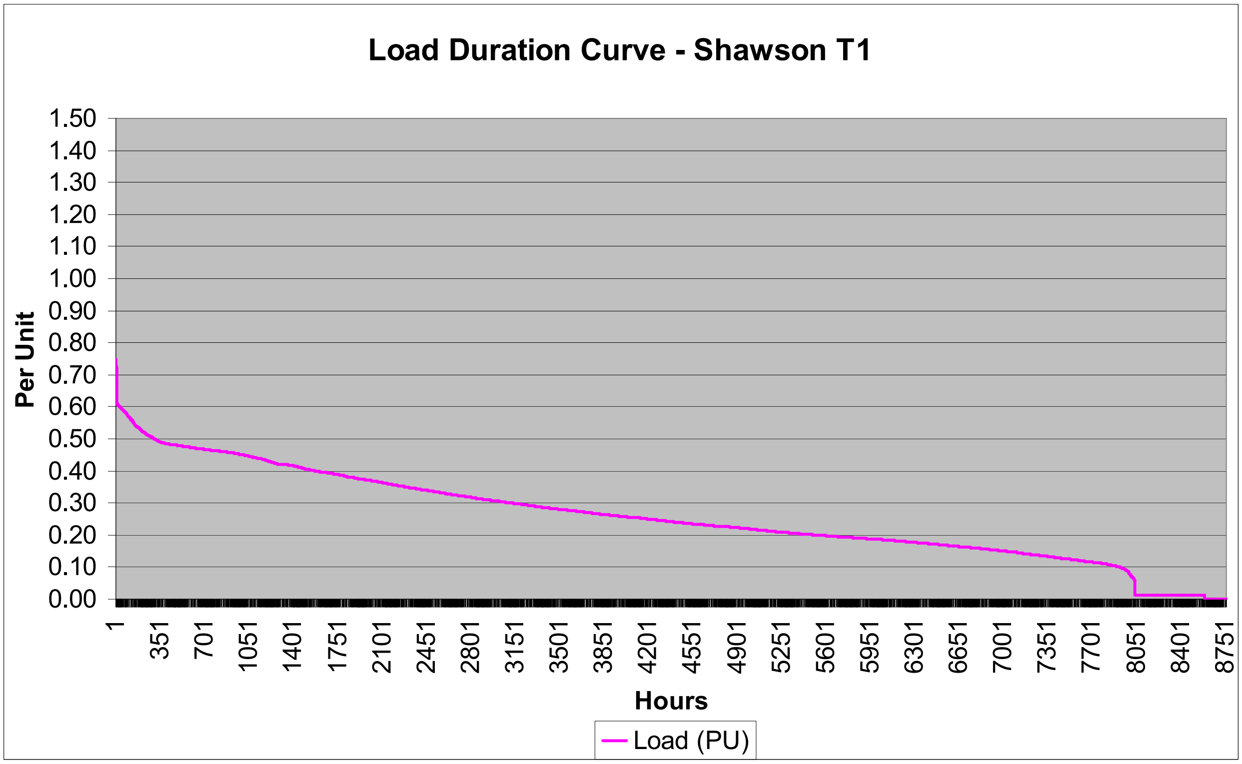
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson T1
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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701
1051
1401
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2101
2451
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3151
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3851
4201
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6301
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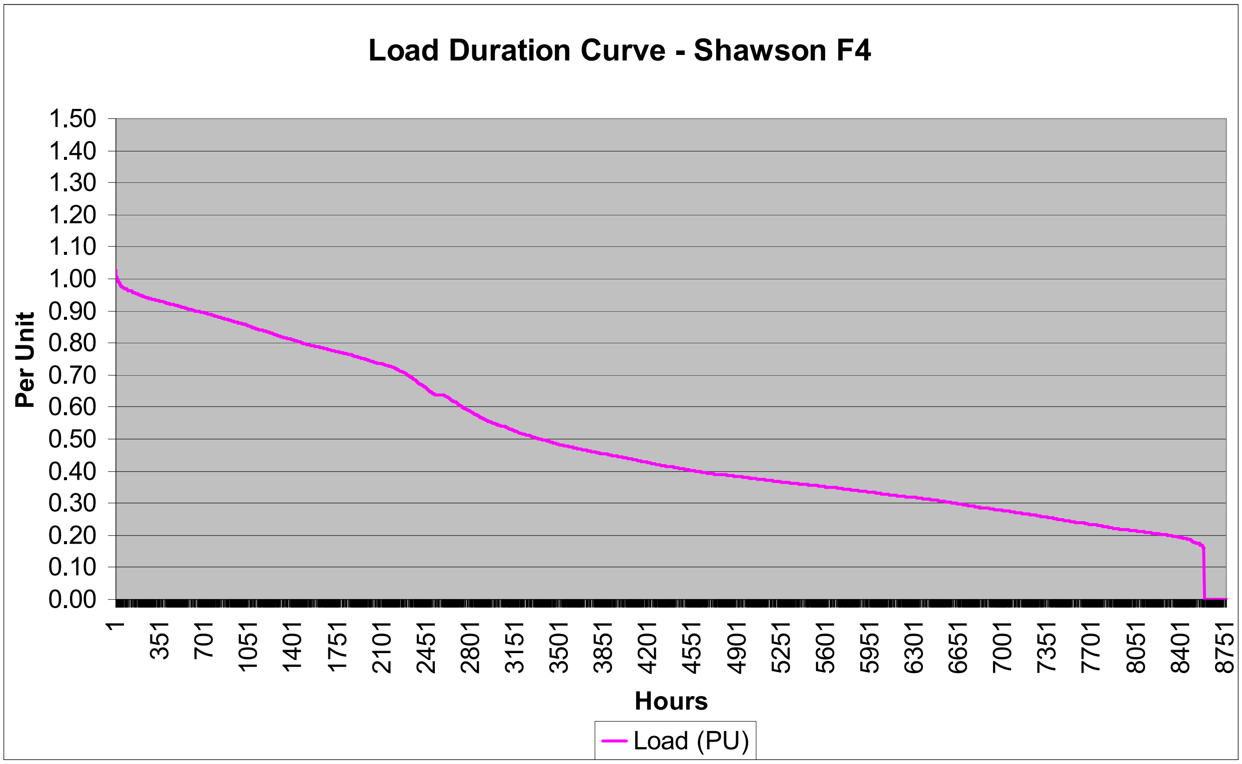
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson F4
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
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3851
4201
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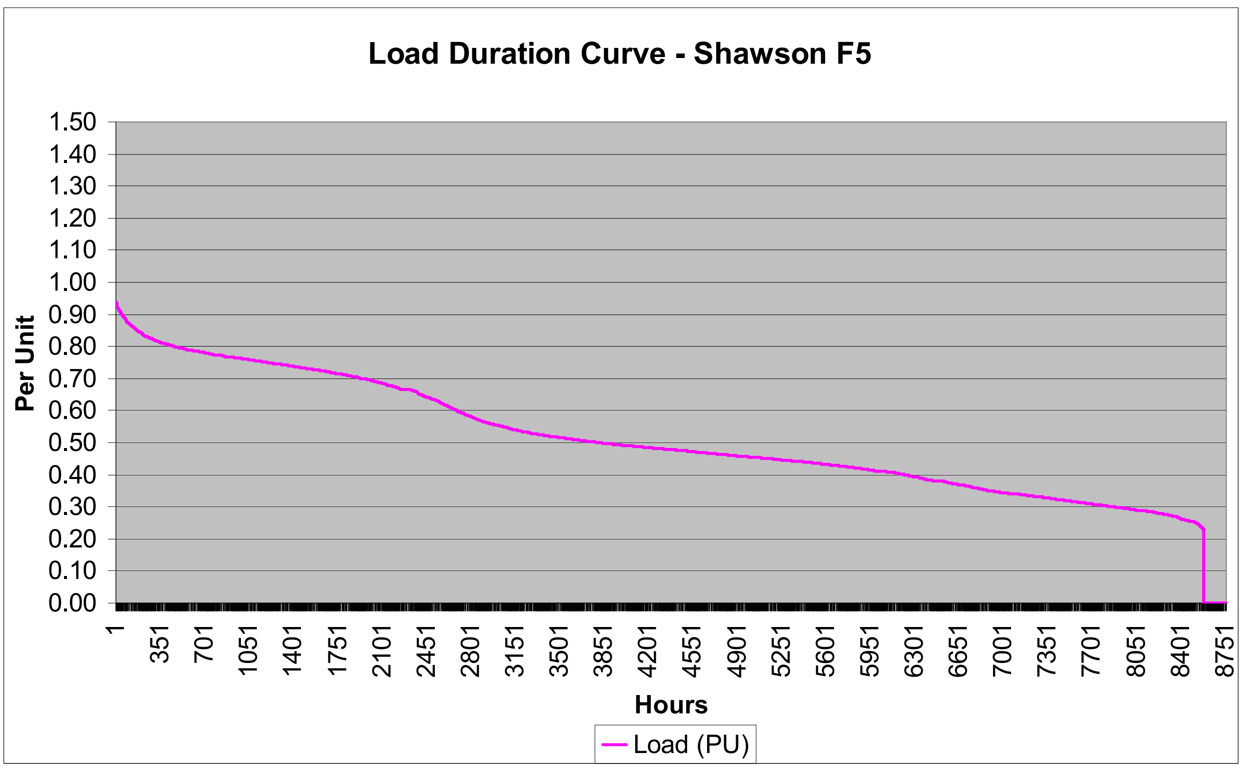
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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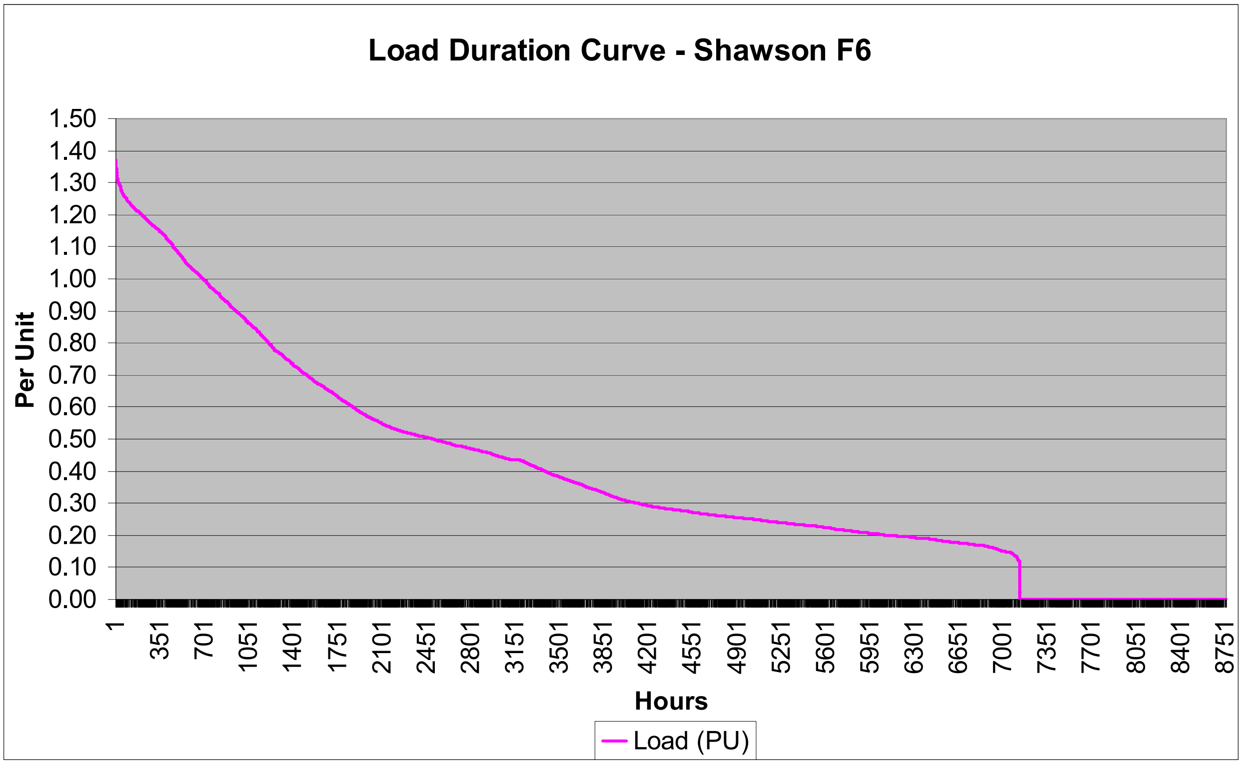
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson F6
Per Unit
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1.30
1.20
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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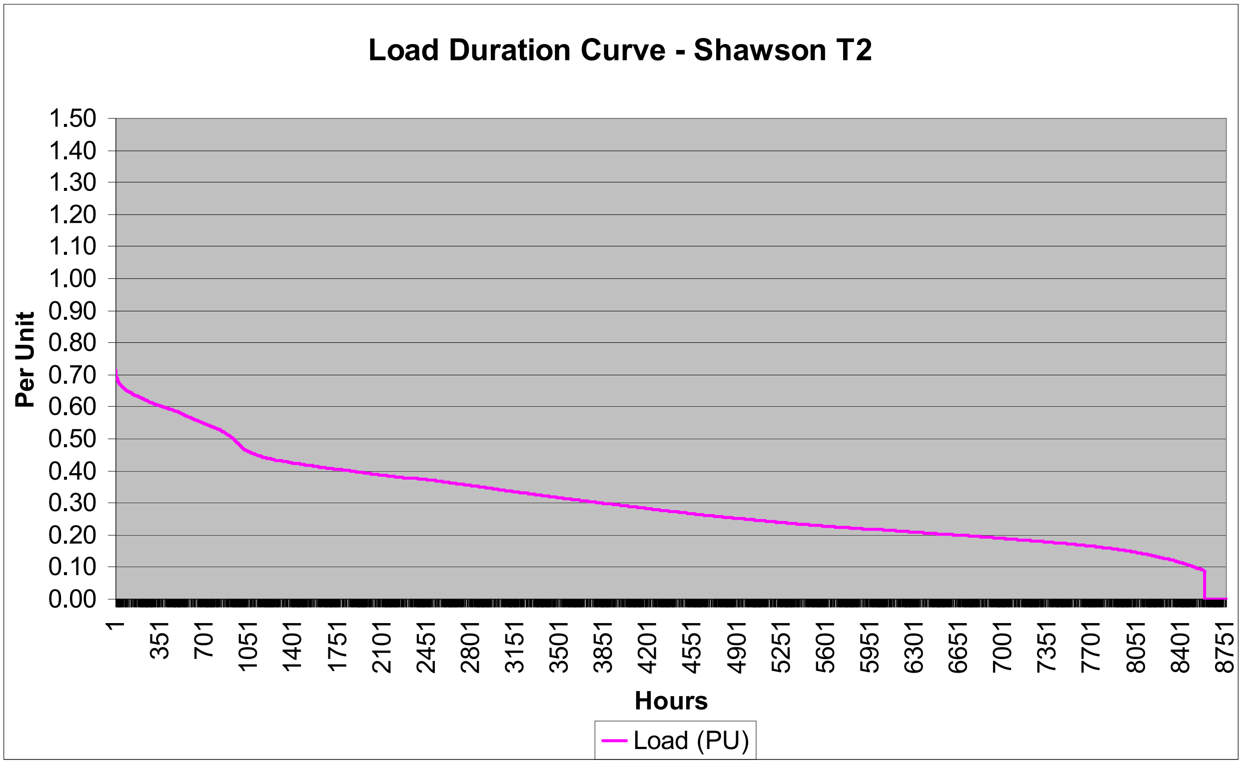
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Shawson T2
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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5601
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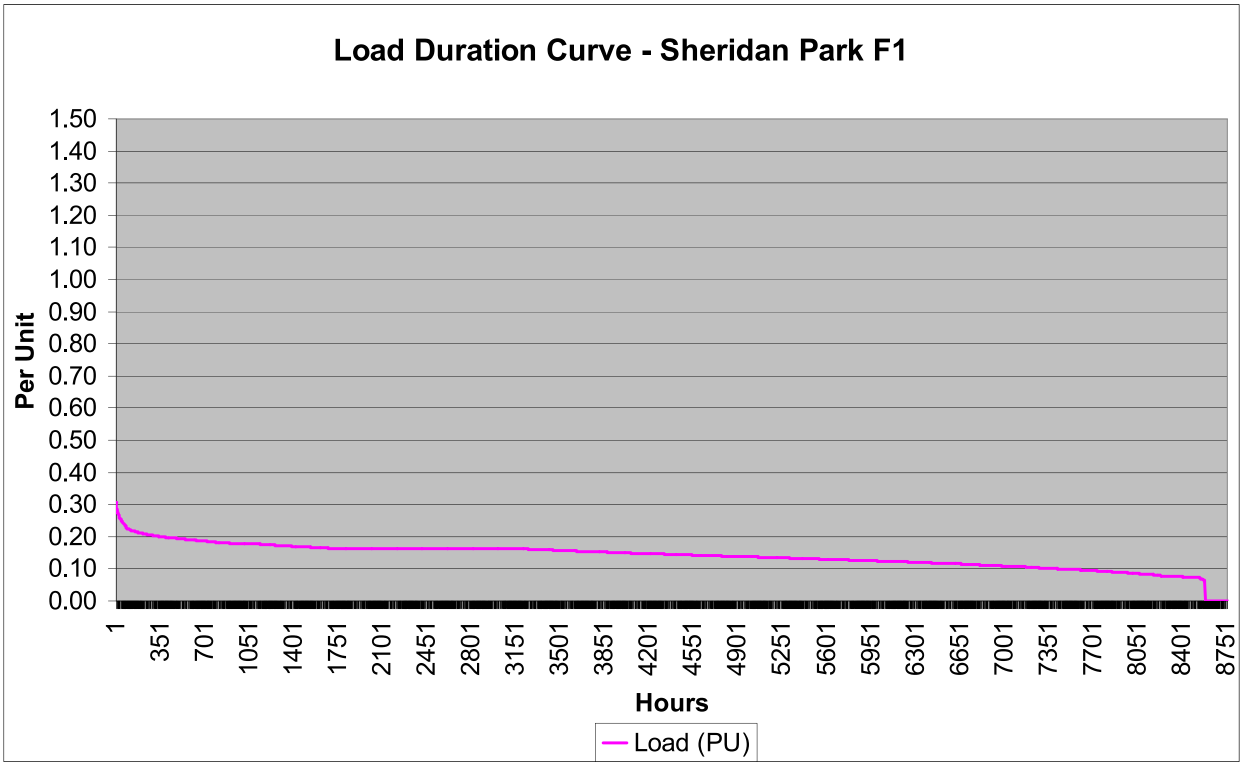
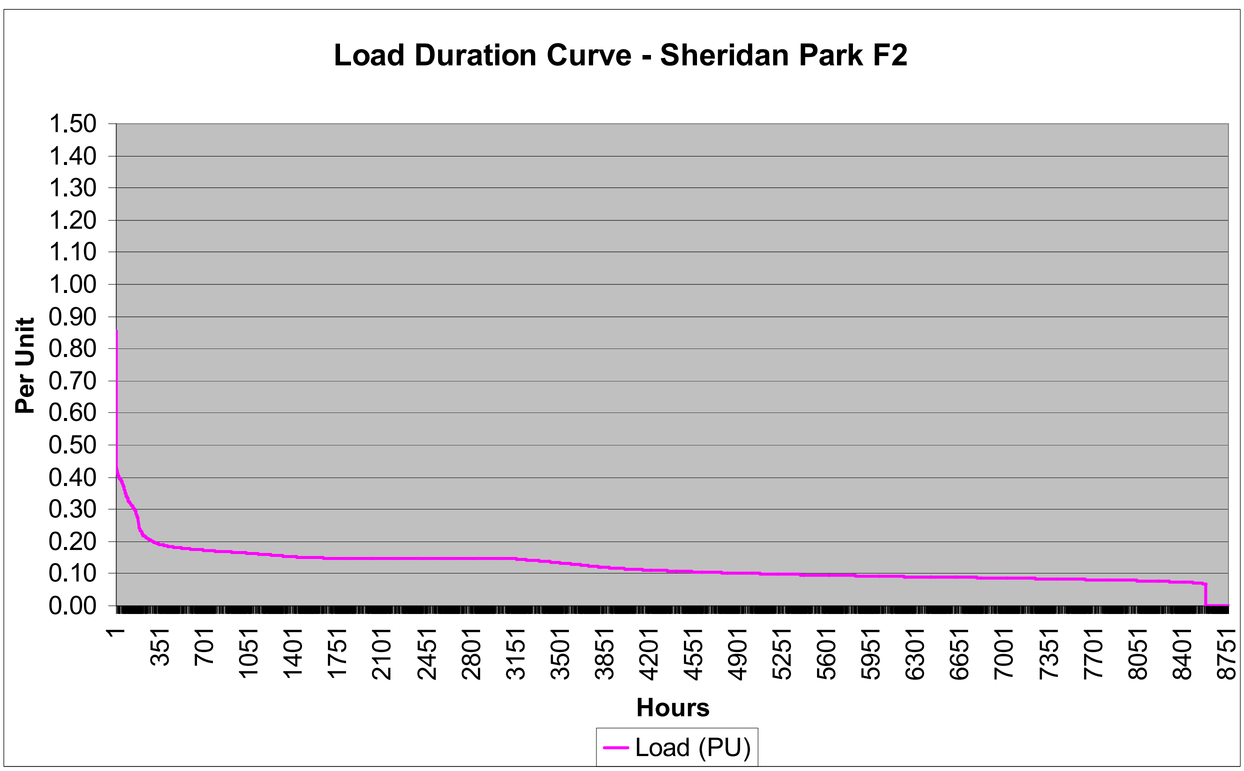
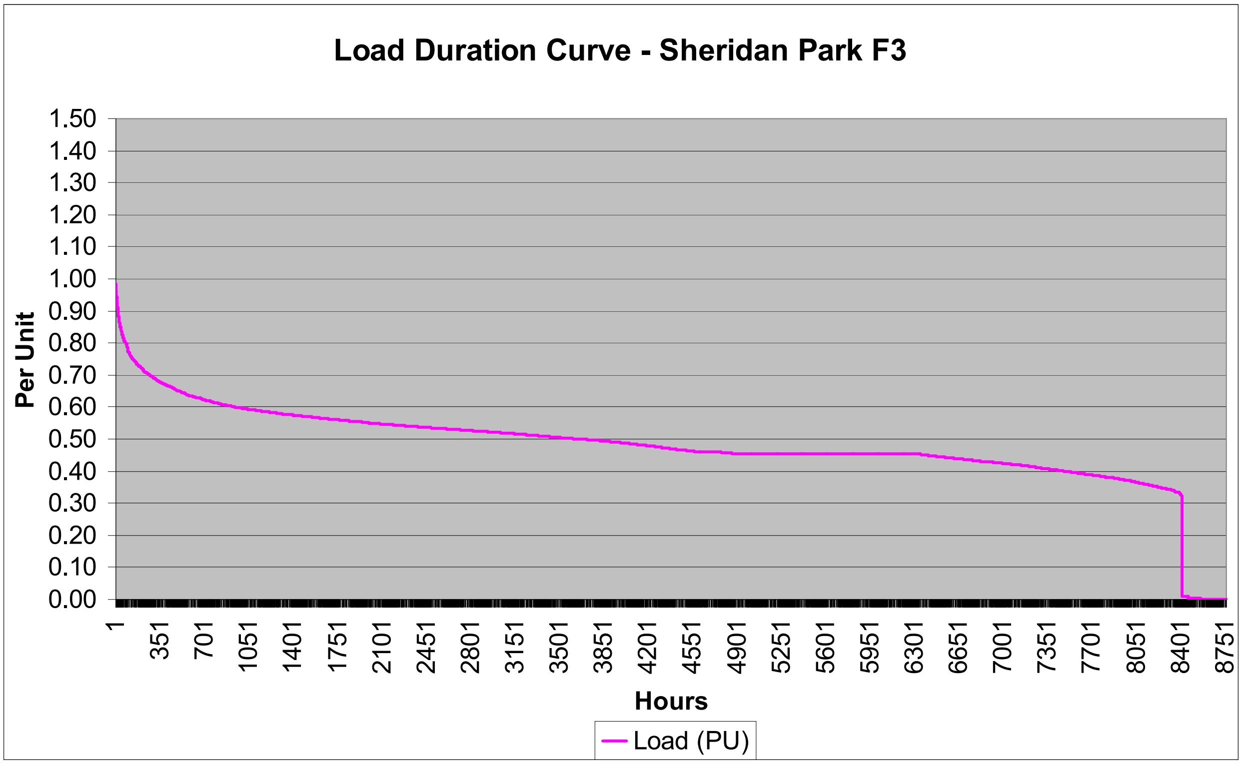
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Sheridan Park MS






Load Duration Curve - Sheridan Park F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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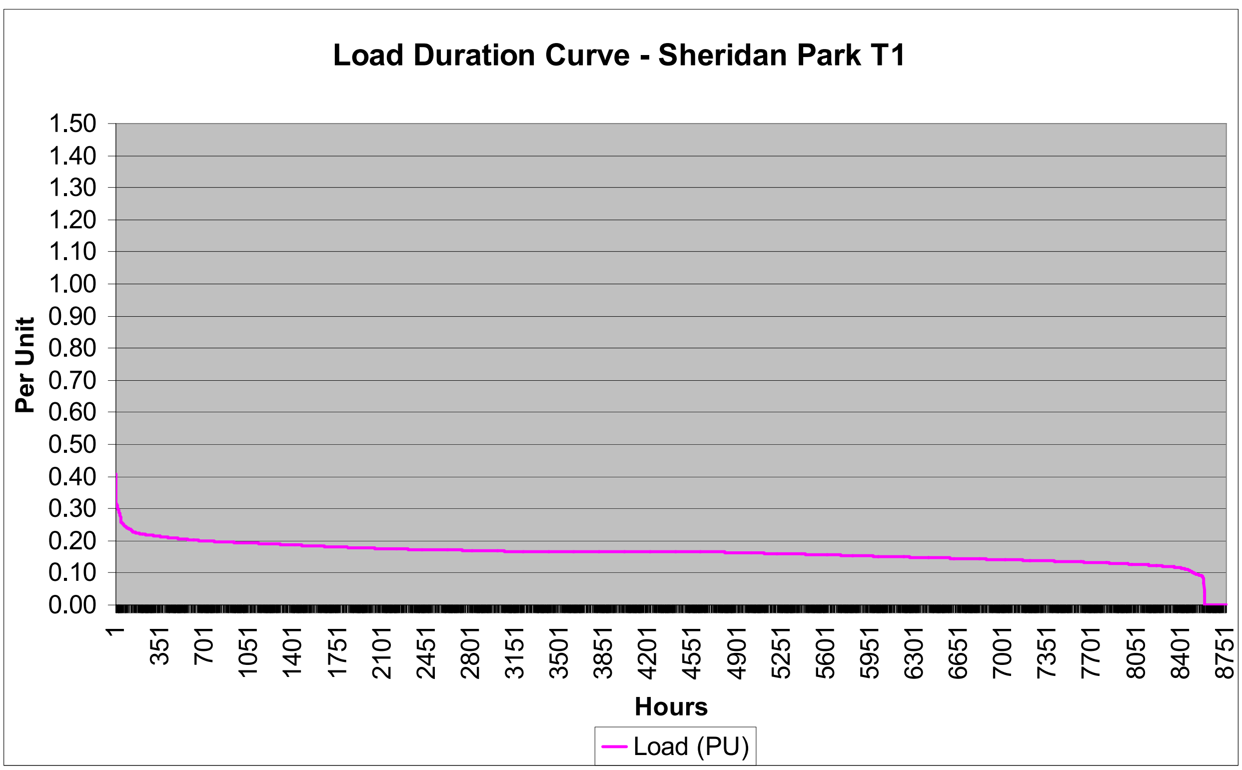
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Sheridan Park T1
Per Unit
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1.30
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
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701
1051
1401
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2451
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4201
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6301
6651
7001
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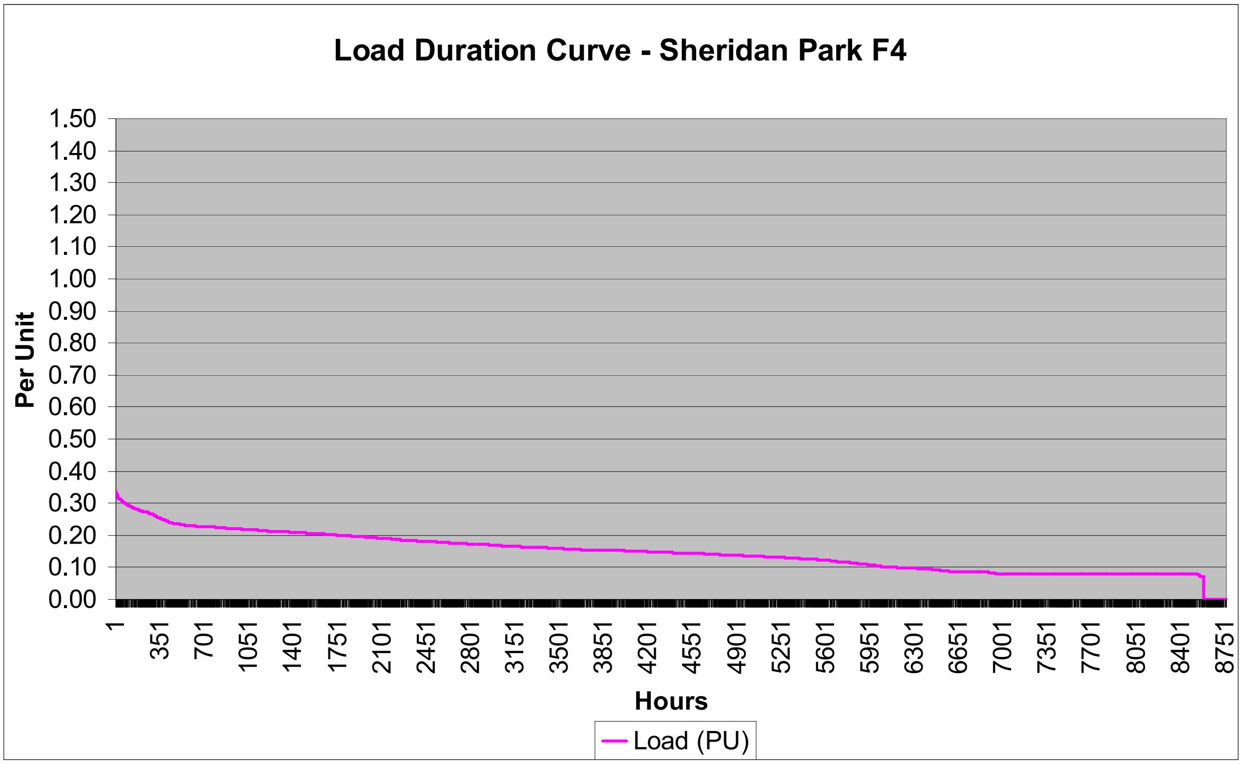
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Sheridan Park F4
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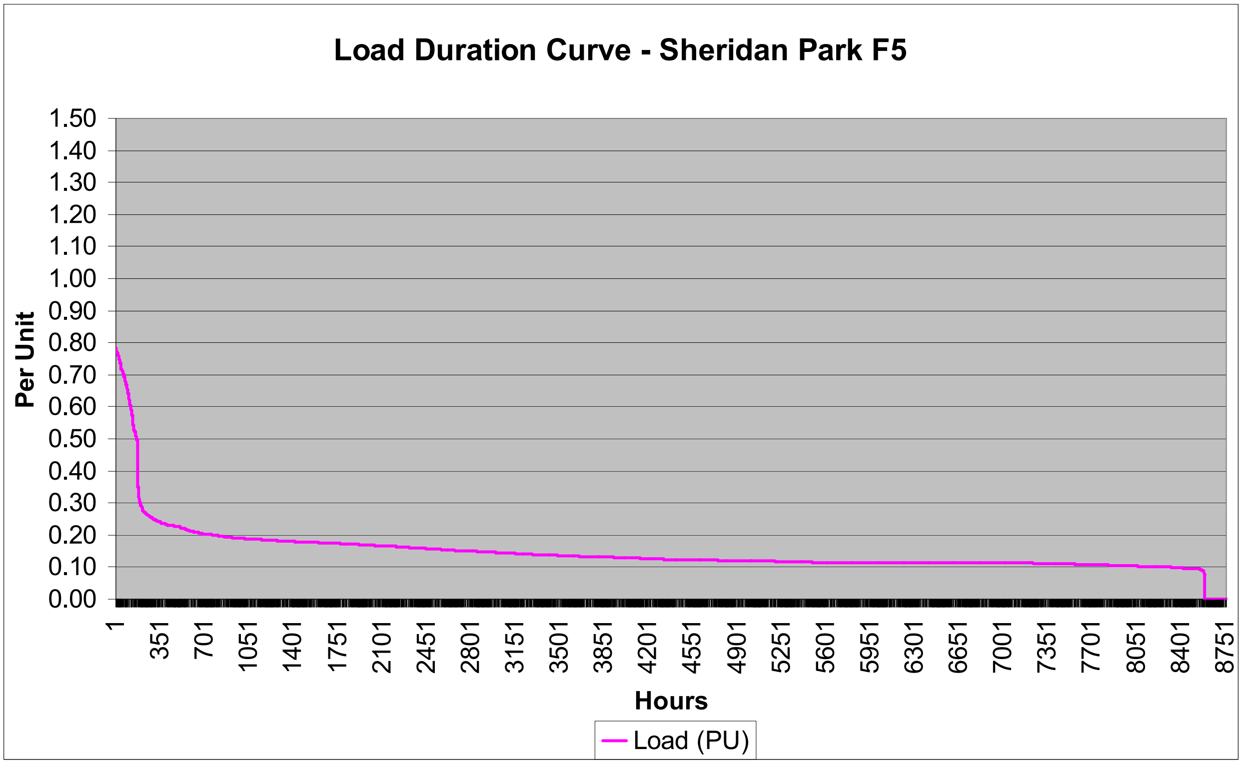
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Sheridan Park F5
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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5601
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6301
6651
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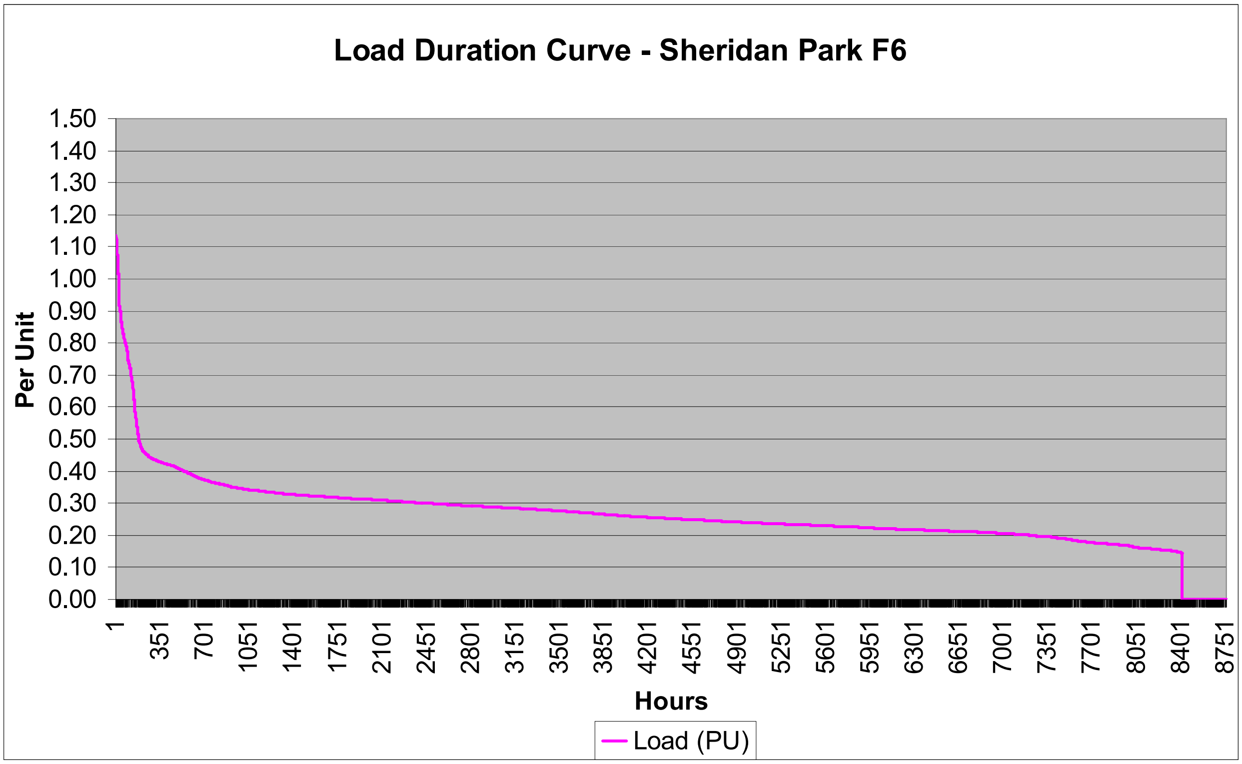
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Sheridan Park F6
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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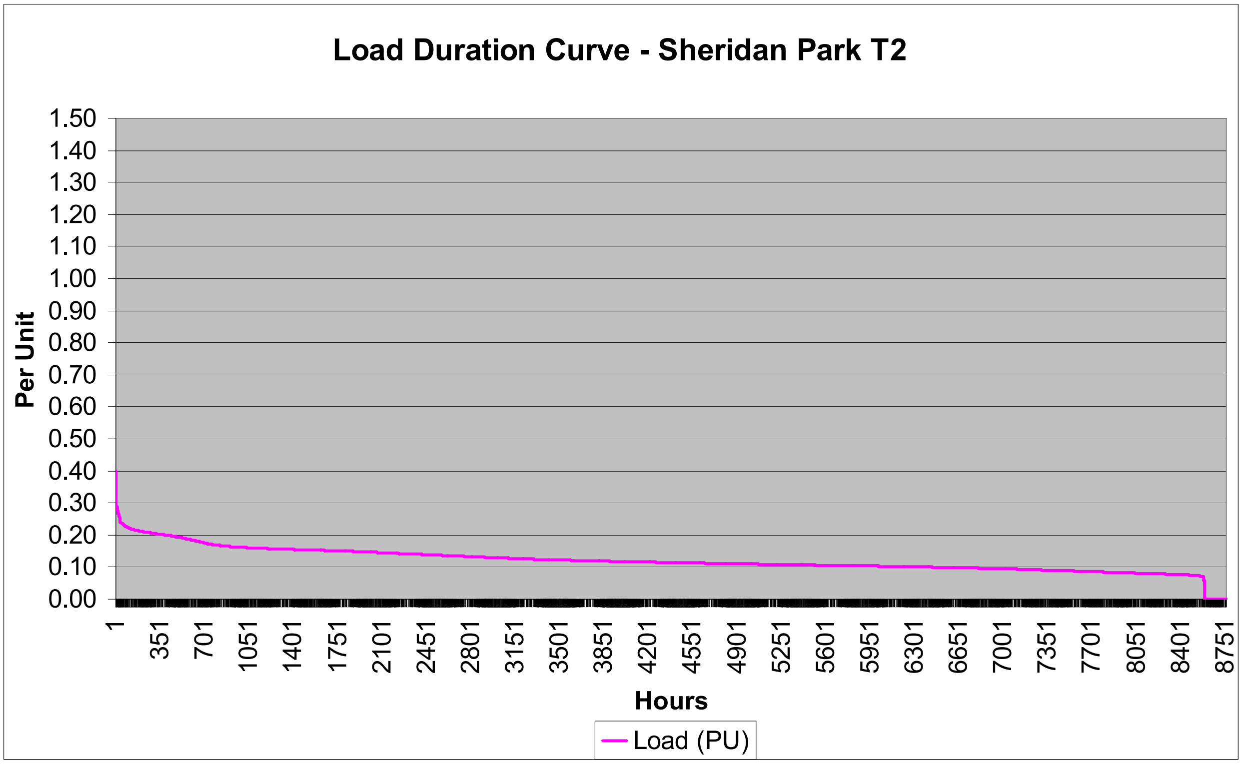
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Sheridan Park T2
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5601
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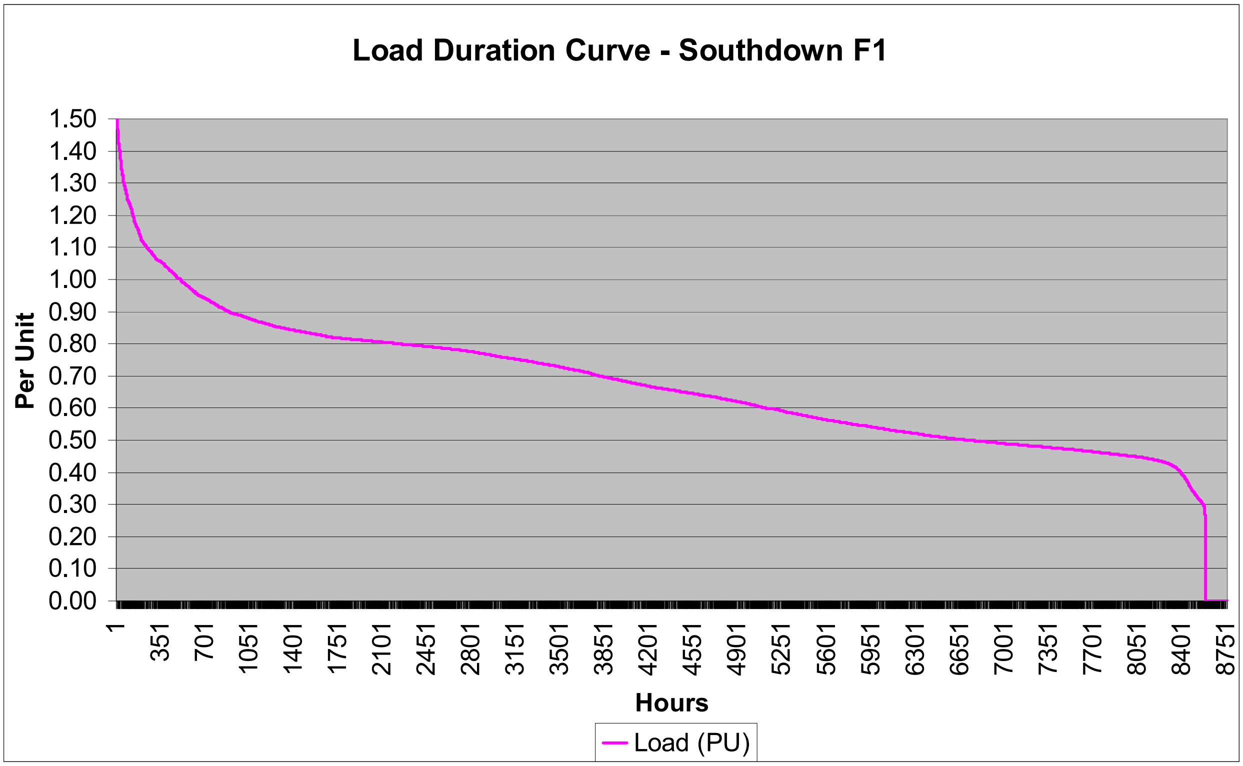
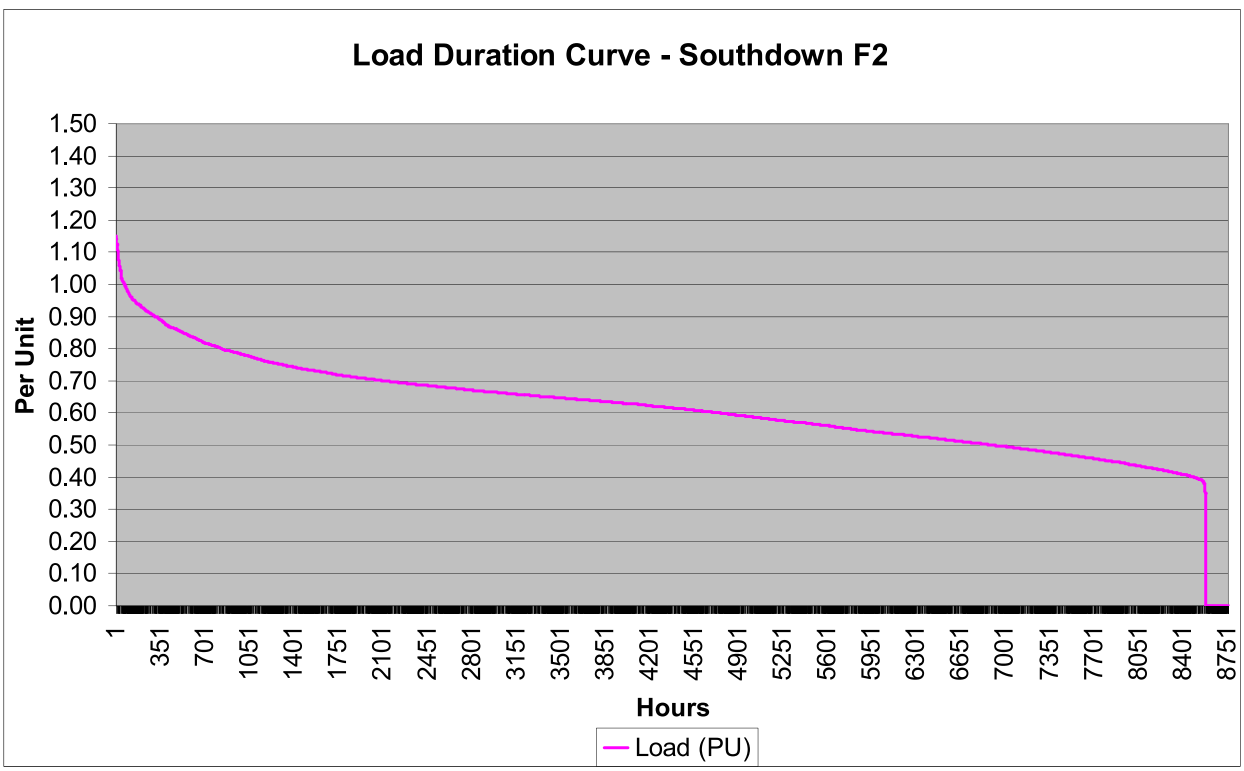
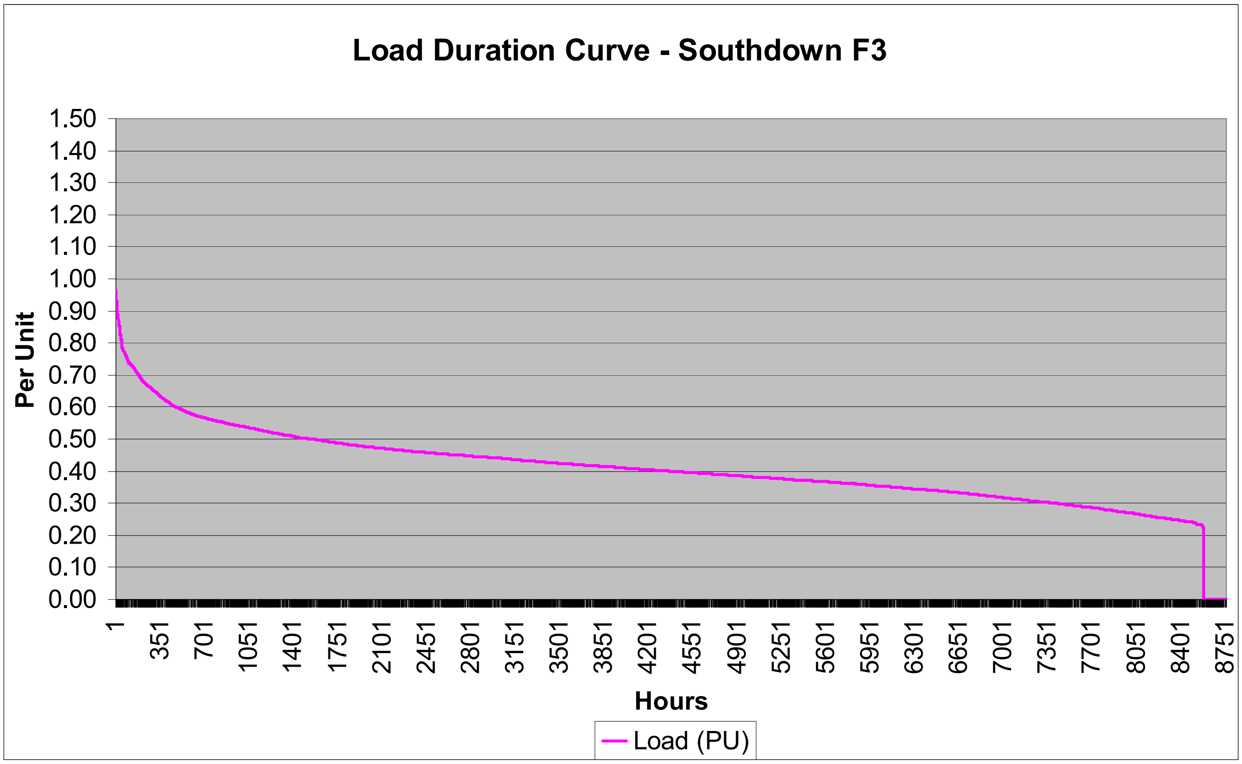
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Southdown MS






Load Duration Curve - Southdown F3
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1.40
1.30
1.20
1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
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6651
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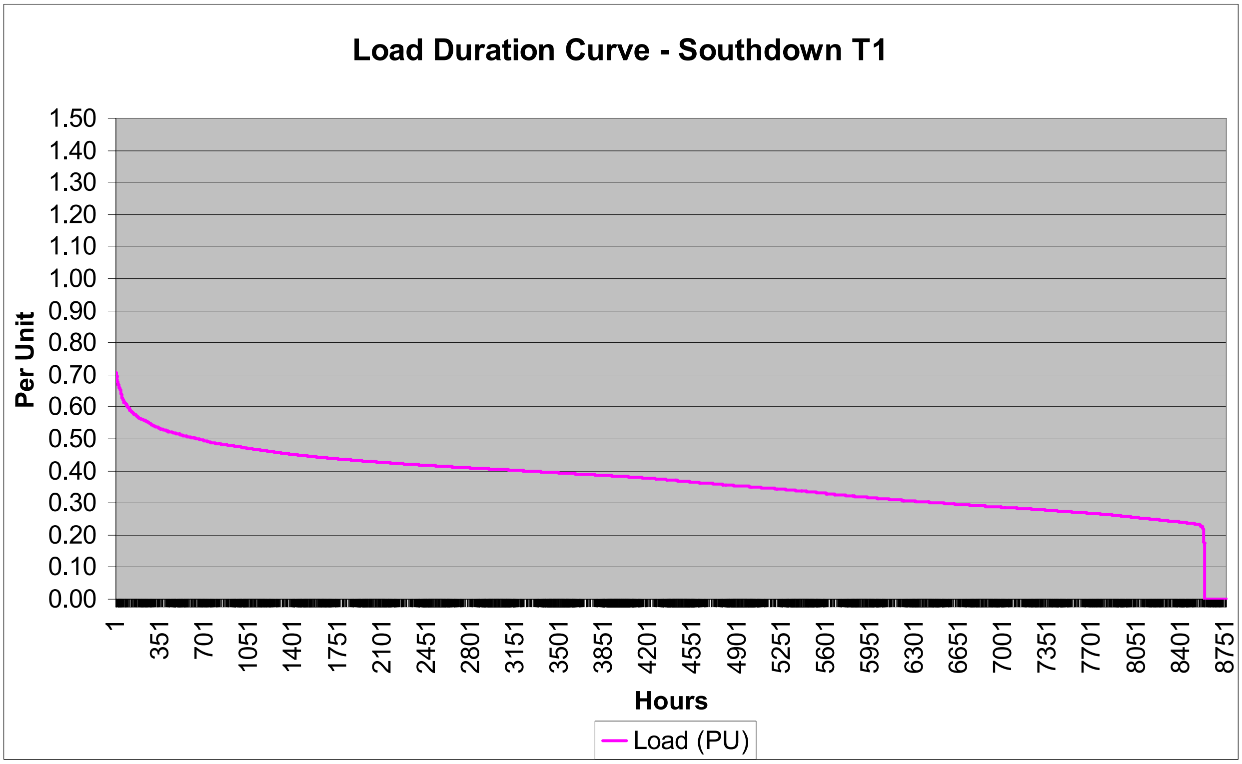
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Southdown T1
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
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6651
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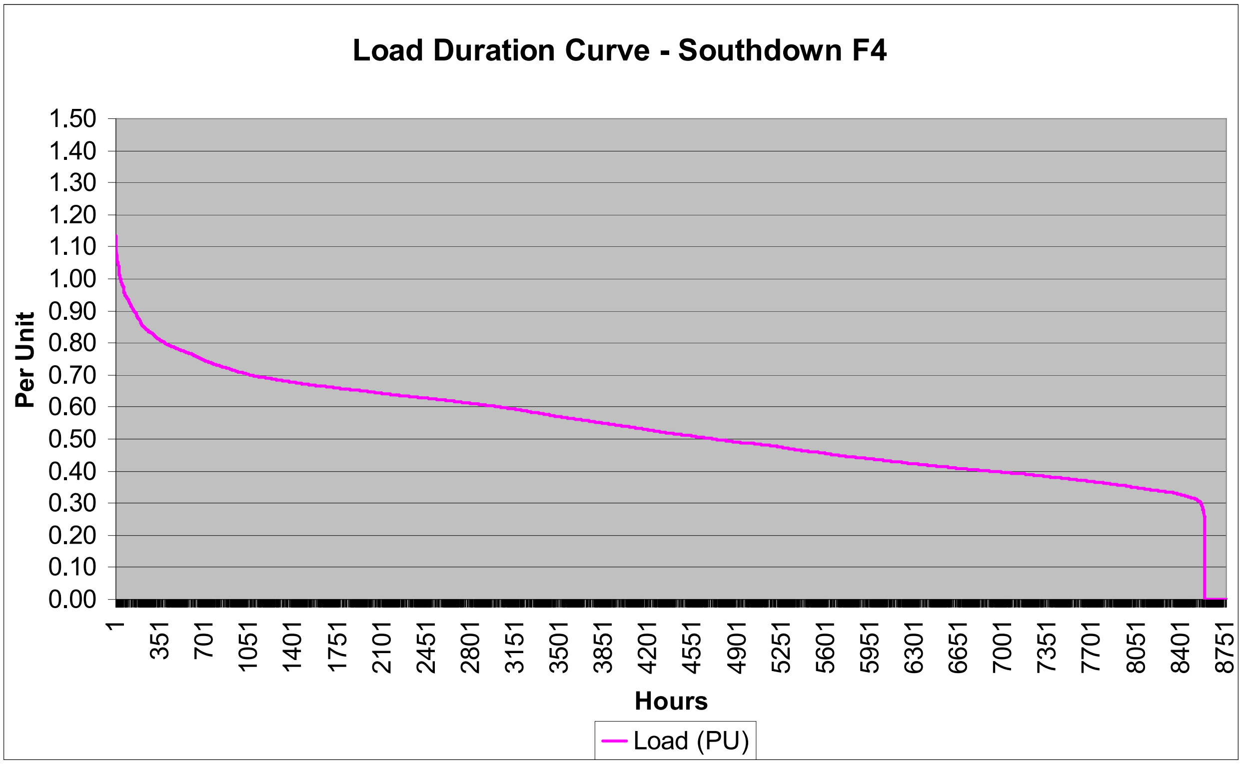
8401
8751
Hours
Load (PU)


Load Duration Curve - Southdown F4
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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6301
6651
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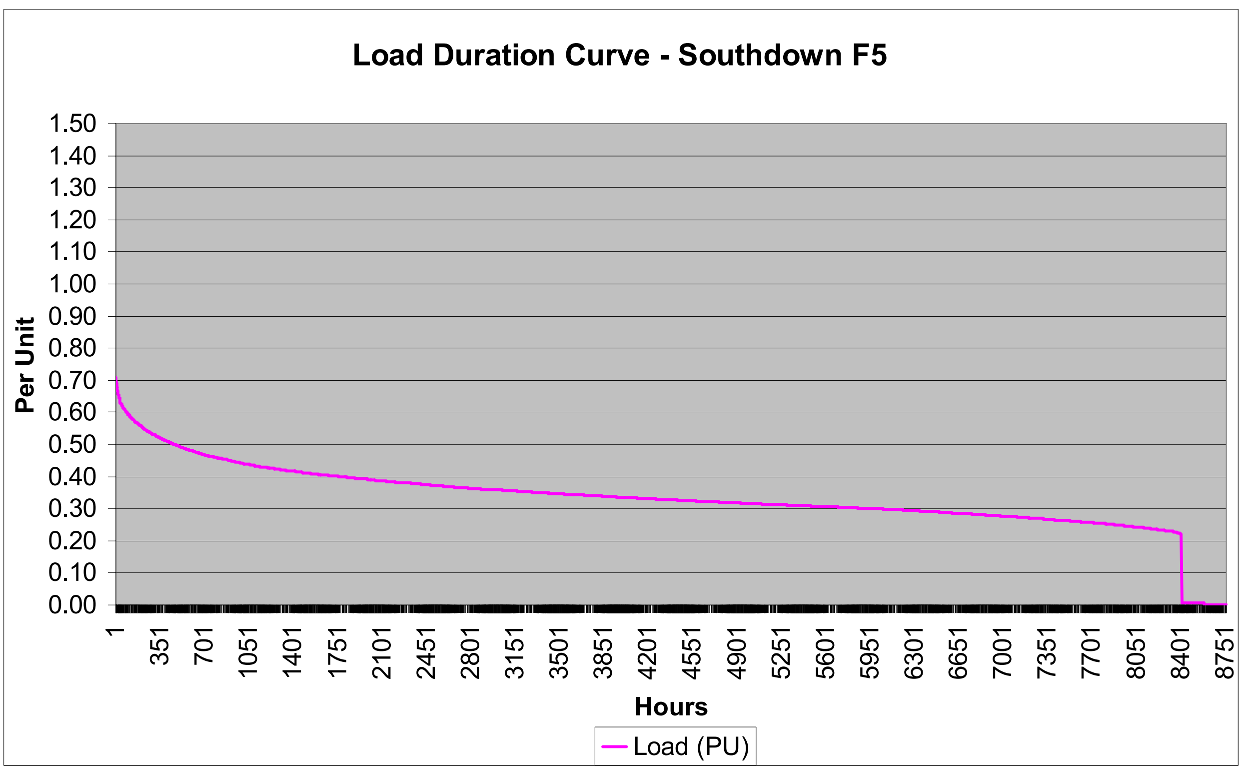
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Southdown F5
Per Unit
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1.20
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1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6651
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8051
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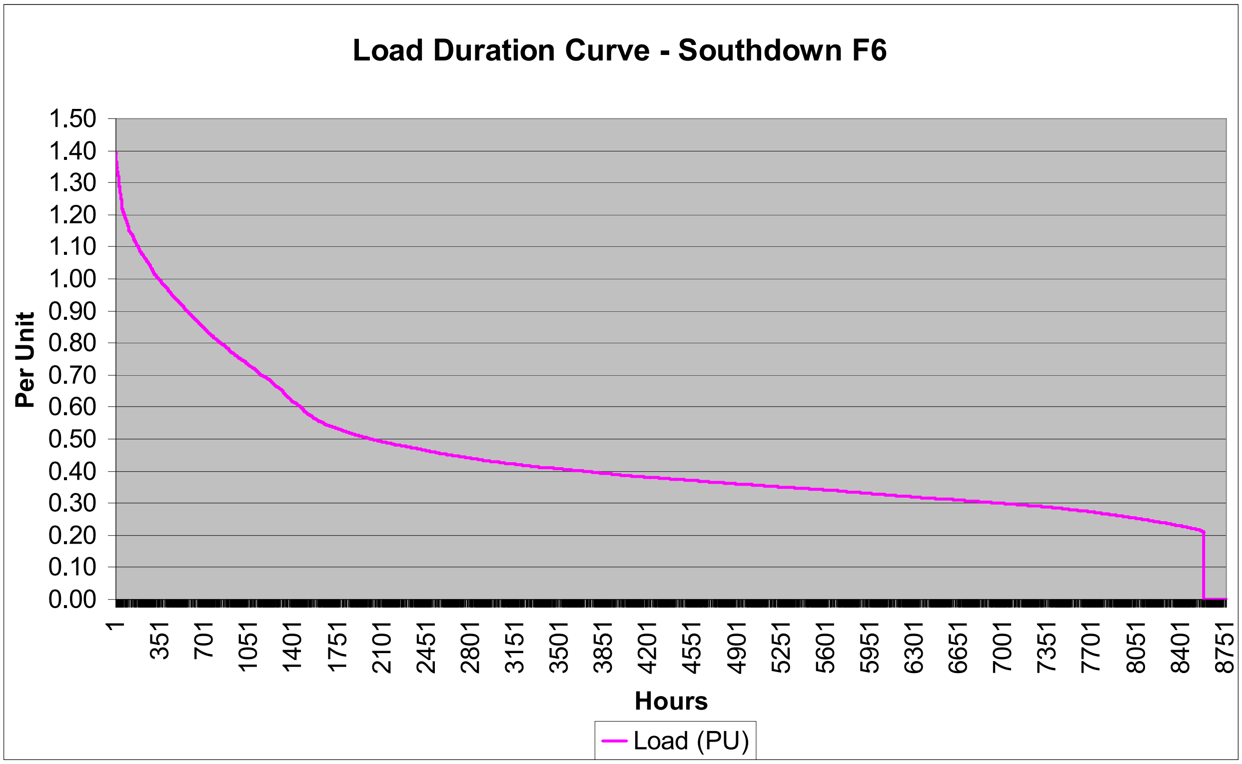
8751
Hours
Load (PU)


Load Duration Curve - Southdown F6
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
3501
3851
4201
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6651
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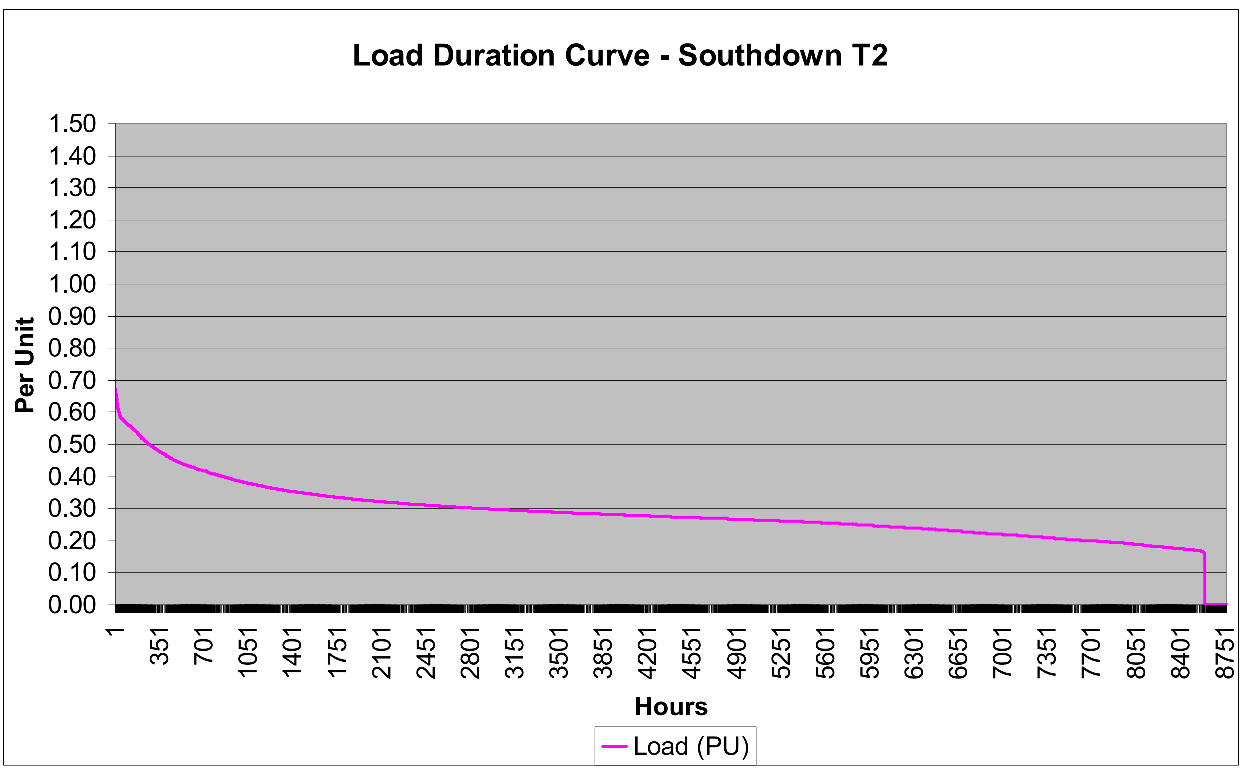
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Southdown T2
Per Unit
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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6651
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7351
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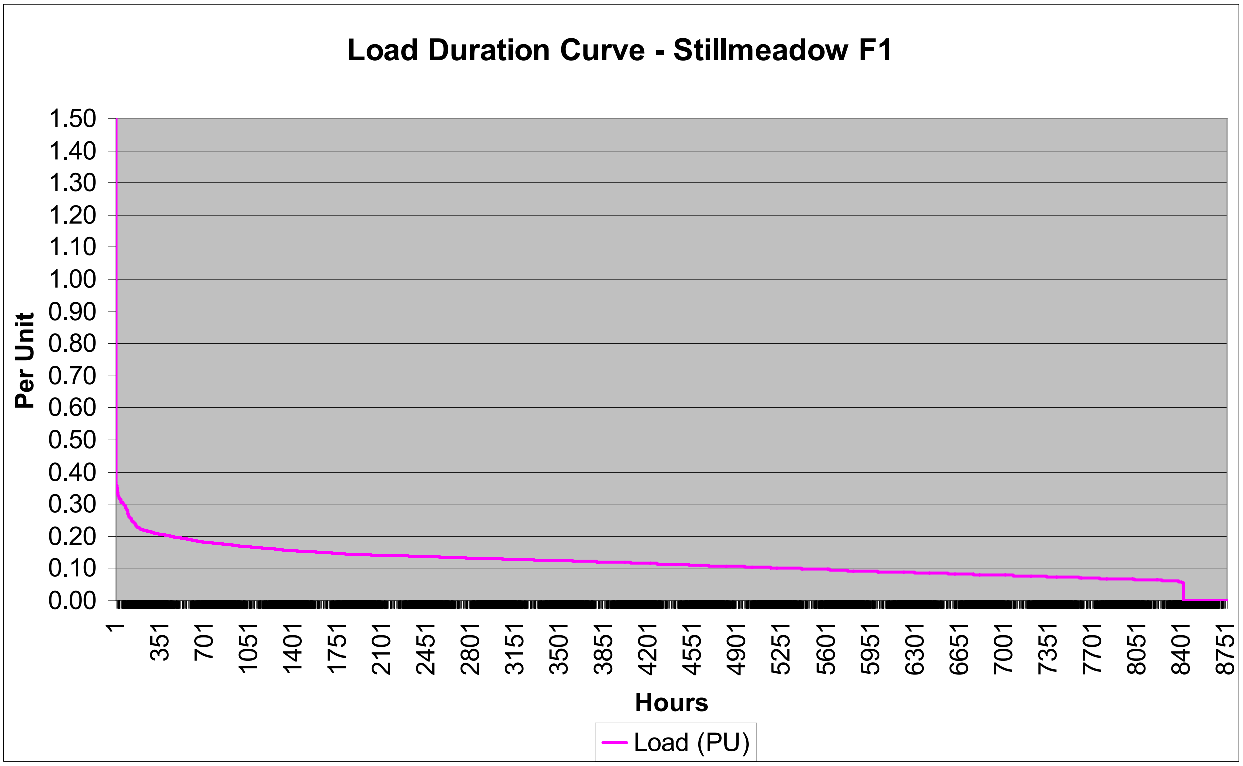
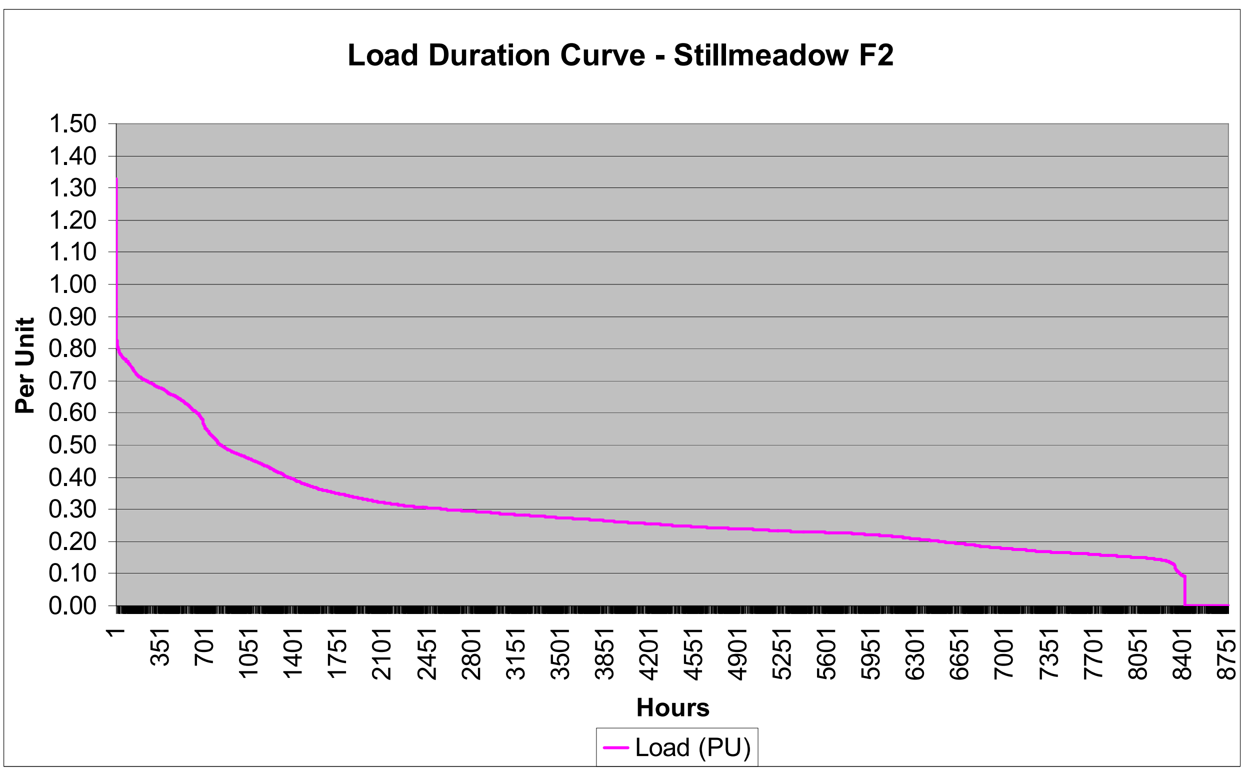
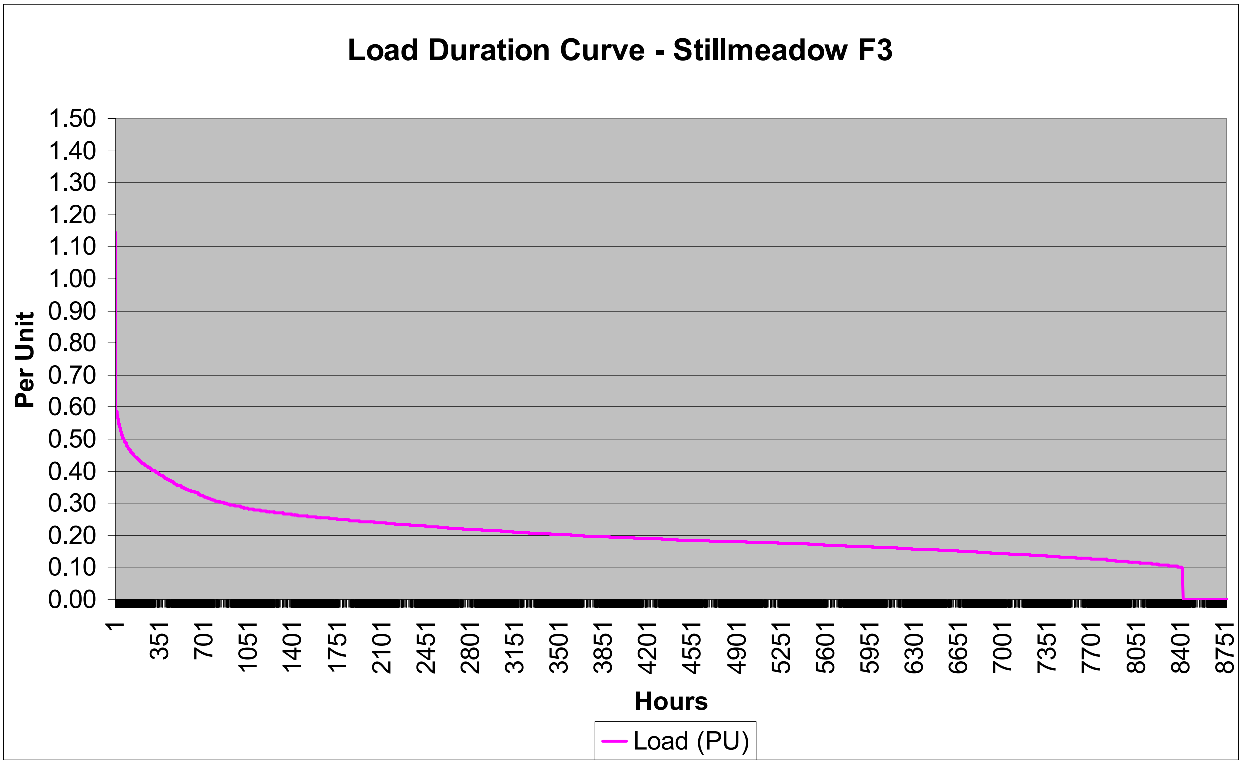
8051
8401
8751
Hours
Load (PU)

Stillmeadow MS






Load Duration Curve - Stillmeadow F3
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
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3851
4201
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6651
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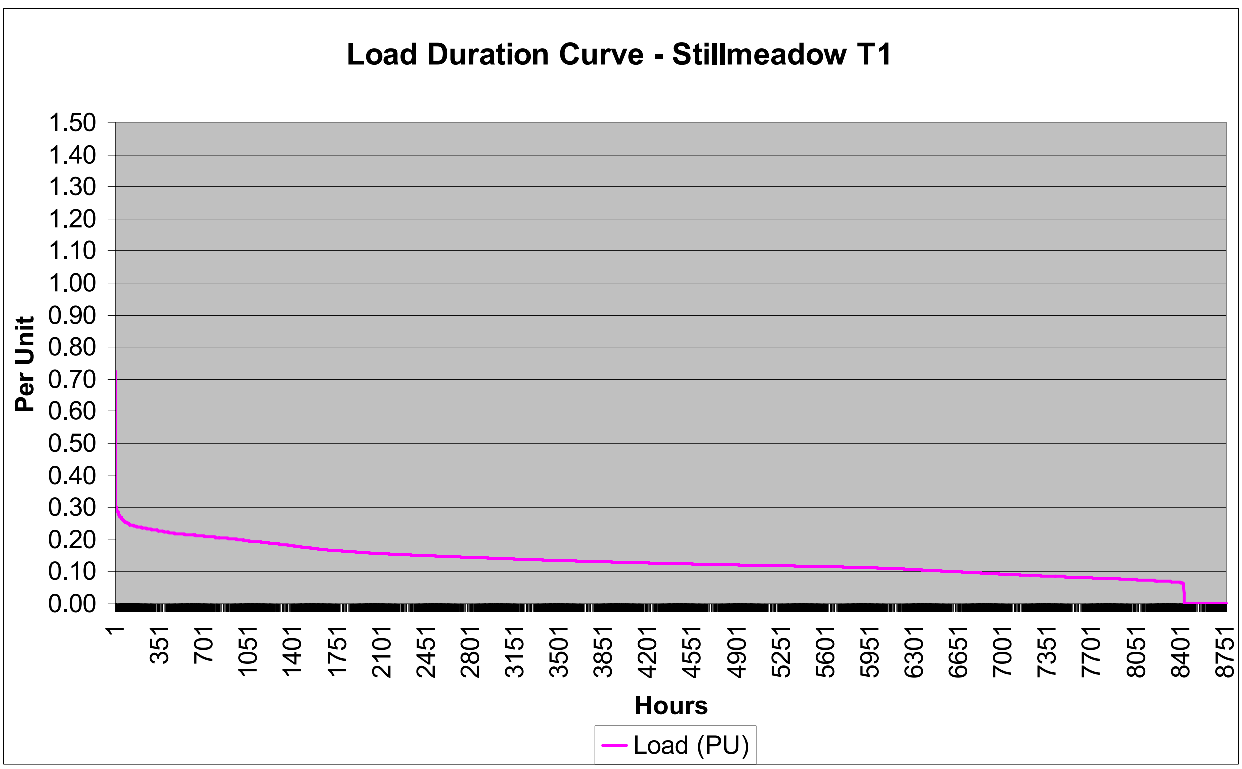
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Stillmeadow T1
Per Unit
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1.30
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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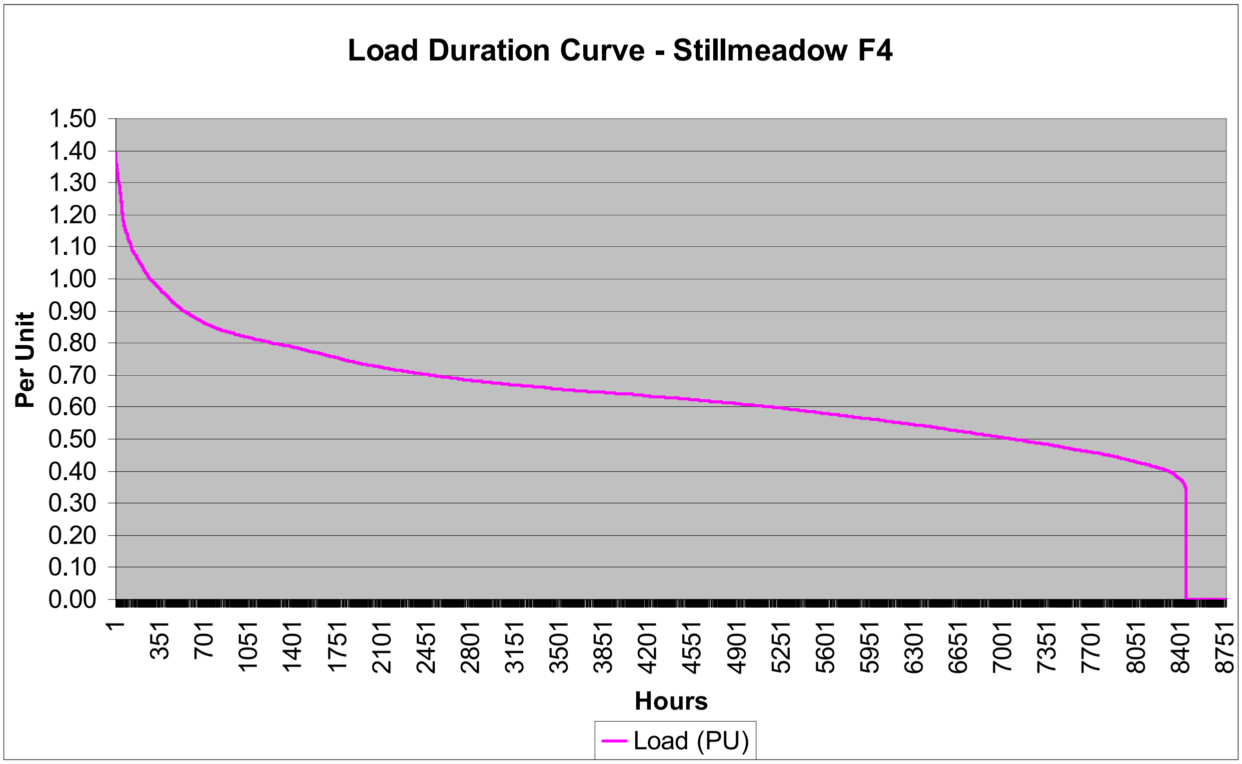
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Stillmeadow F4
Per Unit
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1.20
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6651
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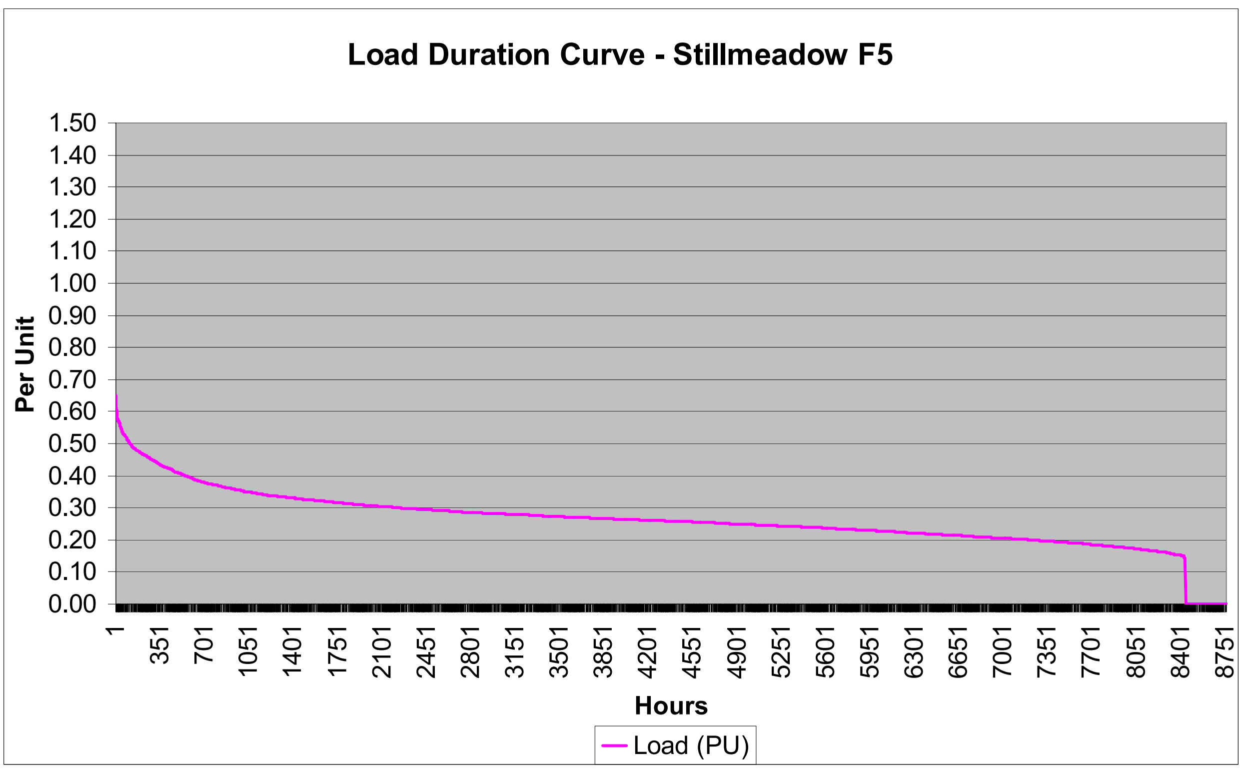
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Stillmeadow F5
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
7001
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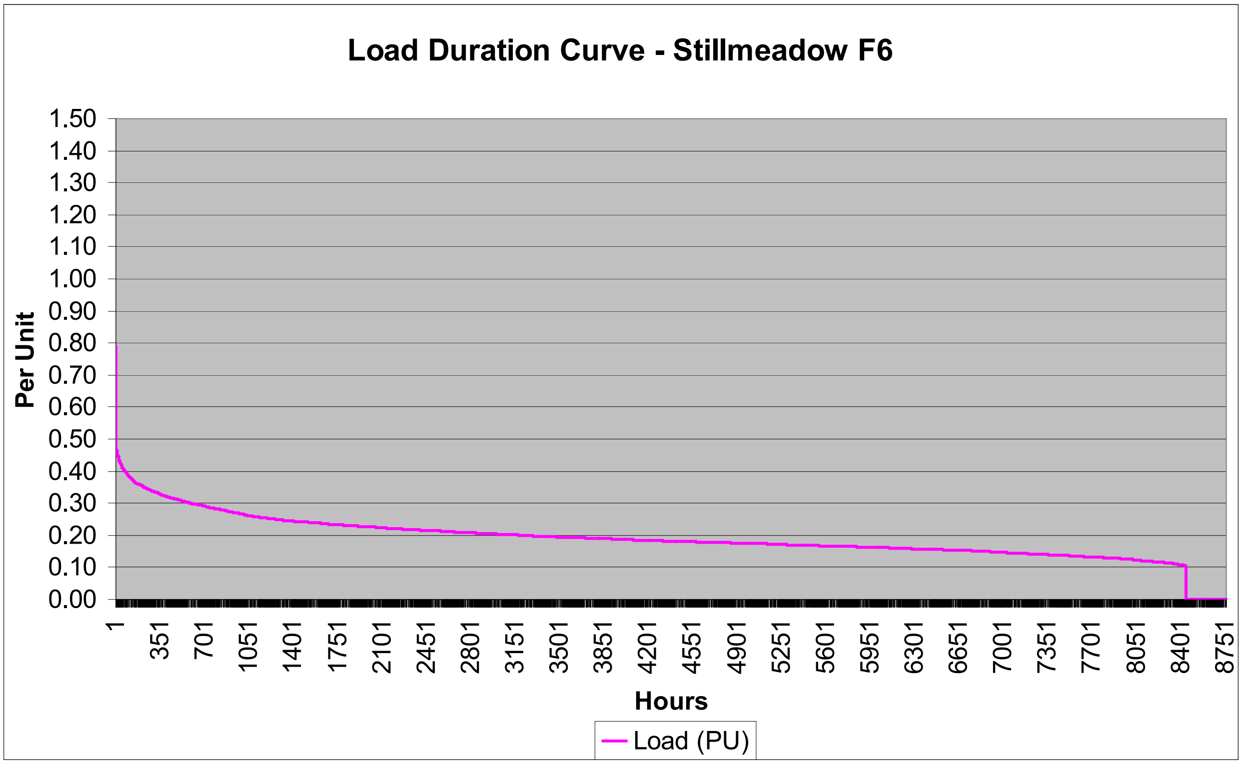
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Stillmeadow F6
Per Unit
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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3151
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3851
4201
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6301
6651
7001
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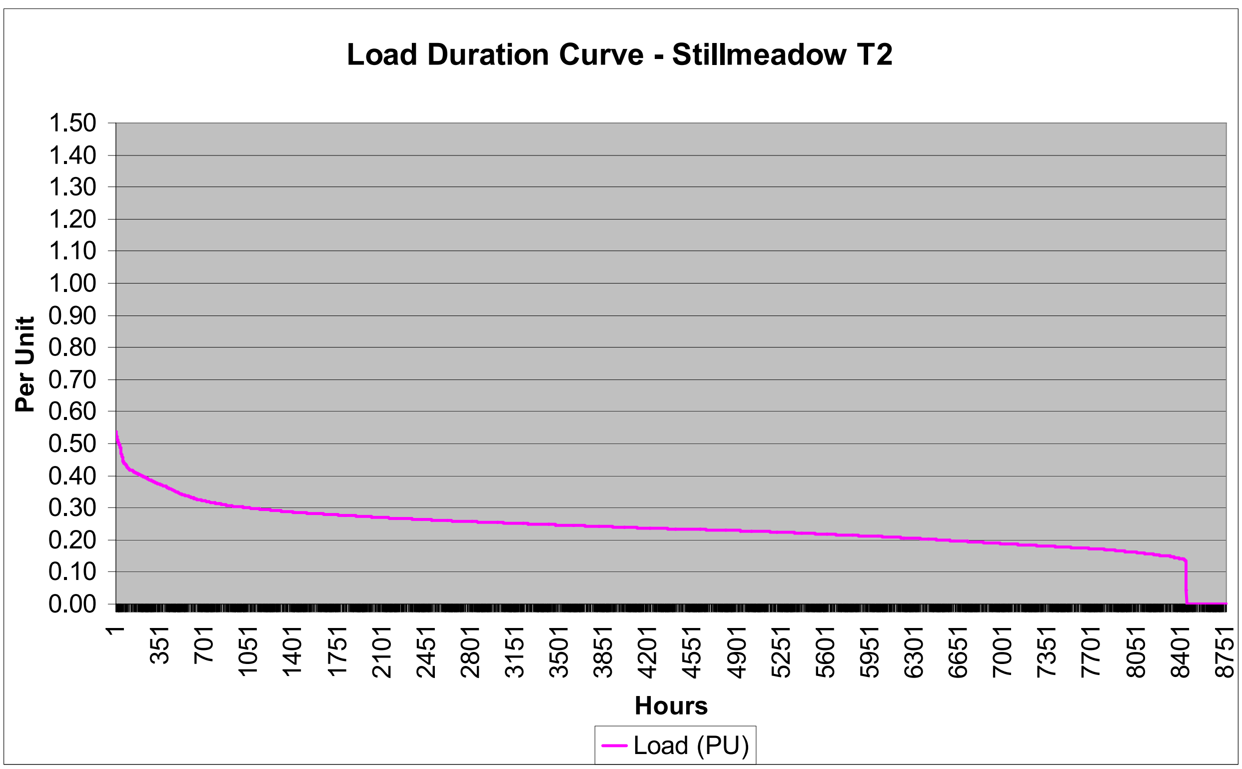
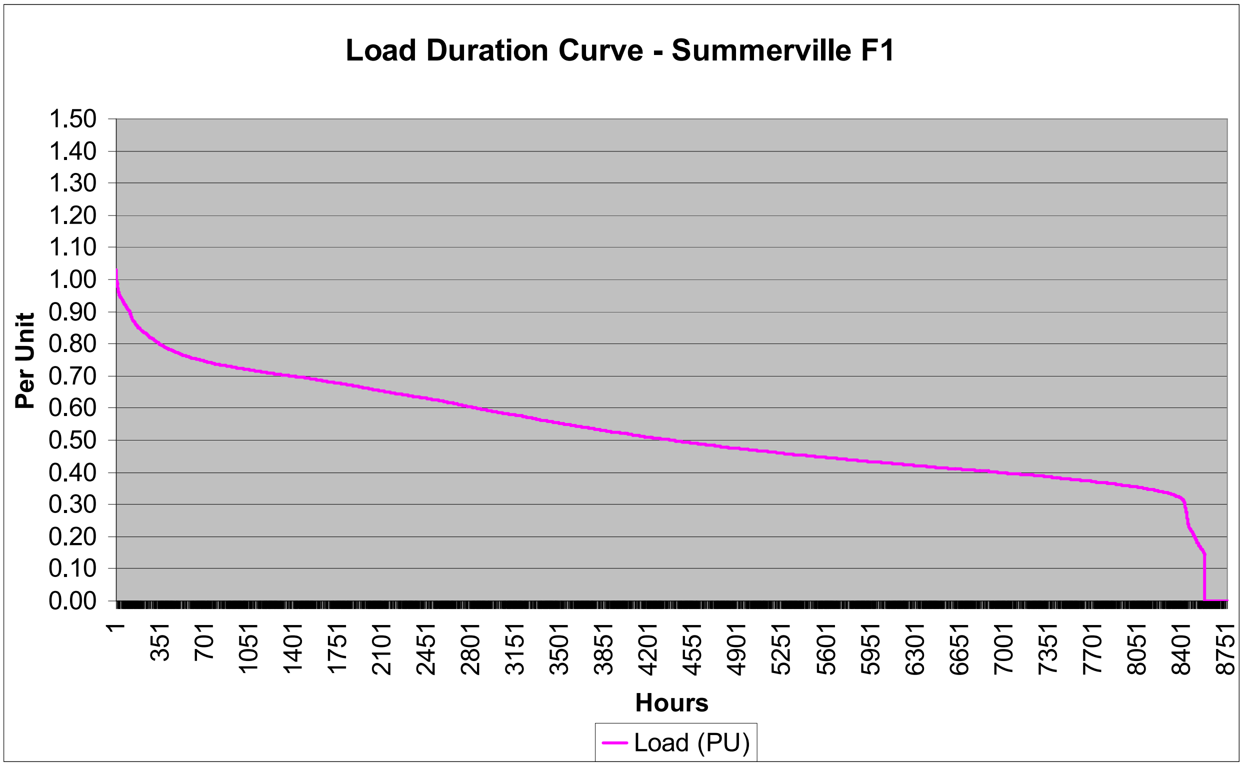
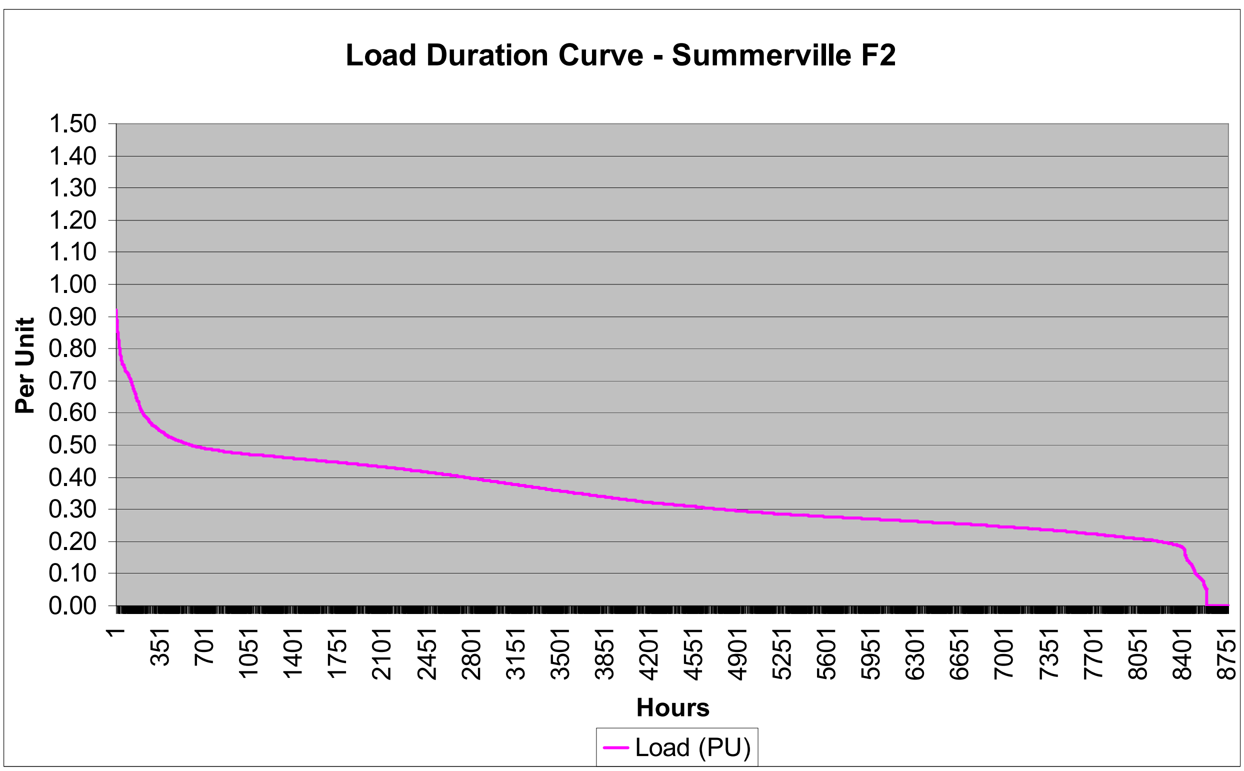
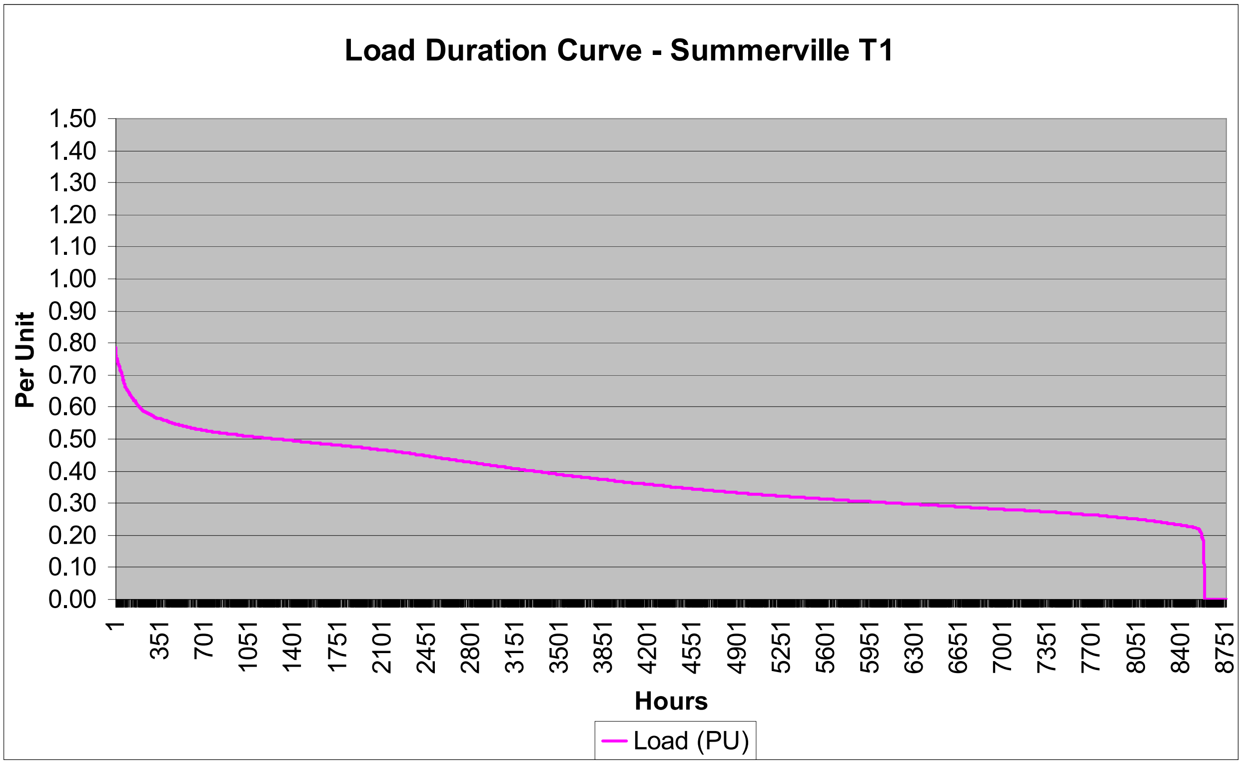
7701
8051
8401
8751
Hours
Load (PU)

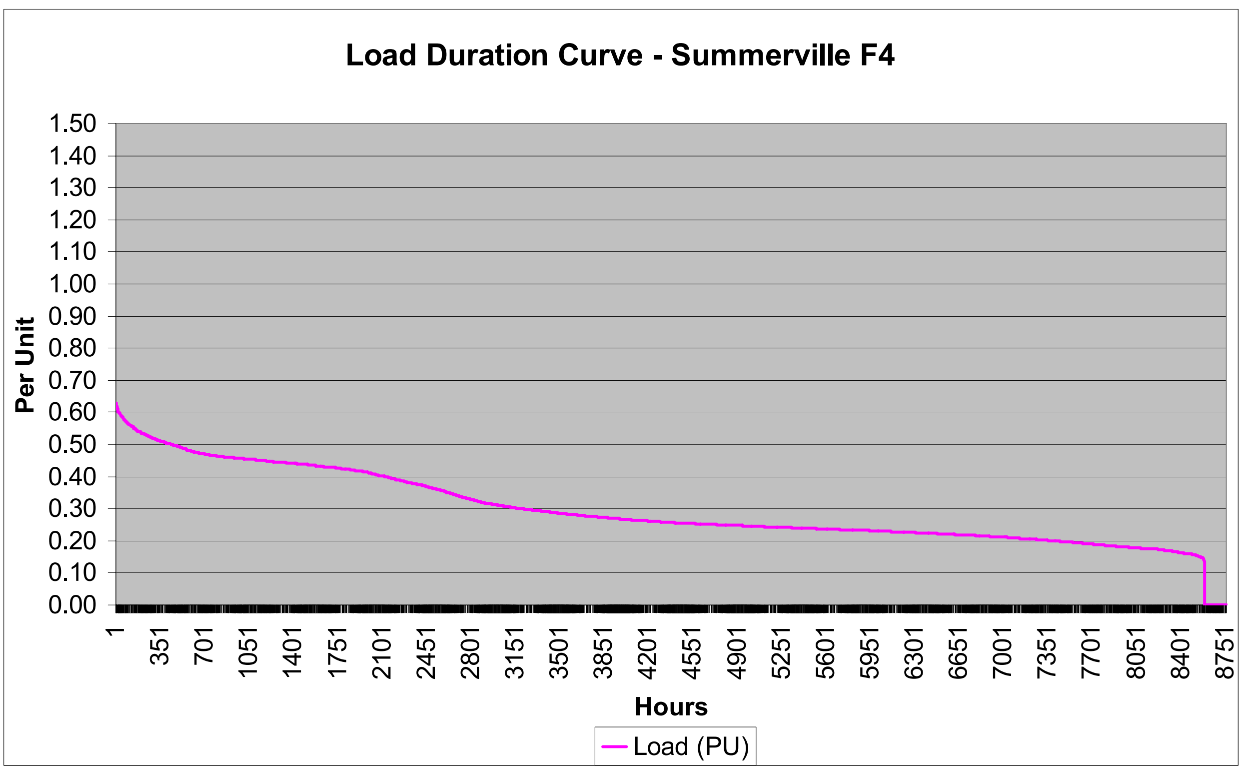

Load Duration Curve - Stillmeadow T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

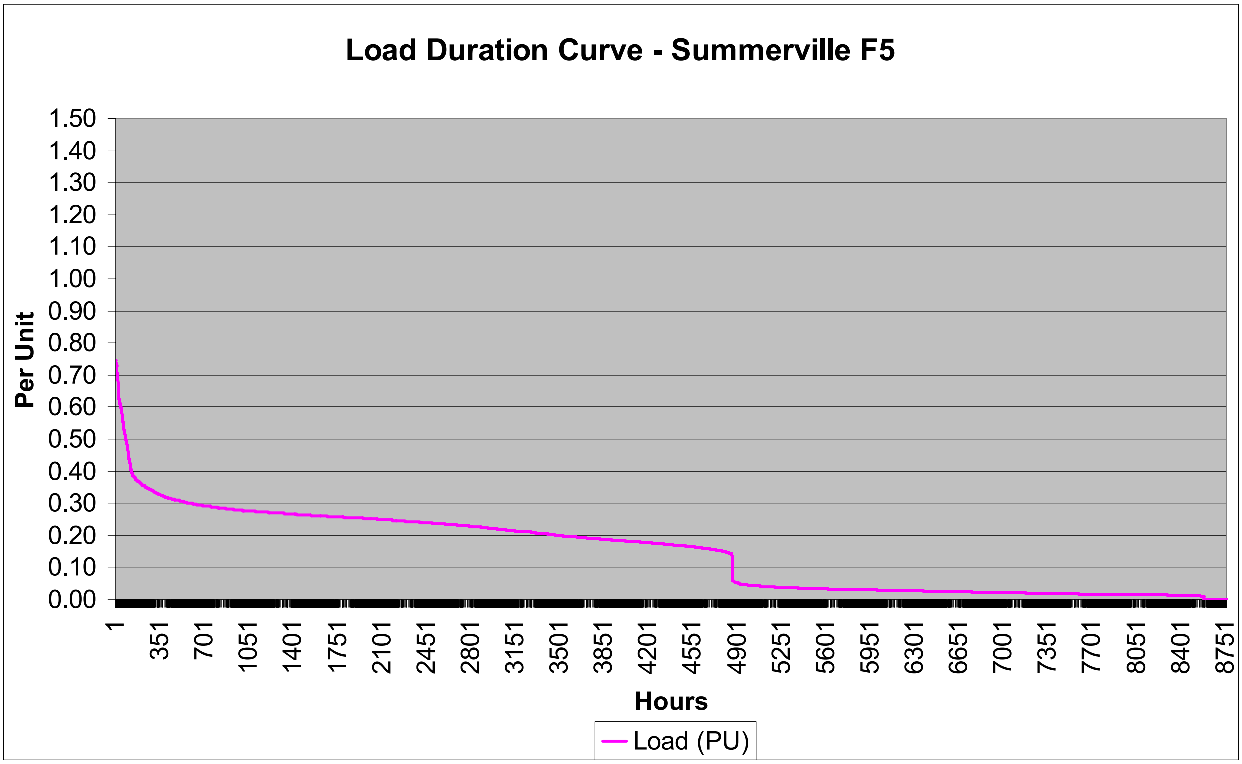
Summerville MS



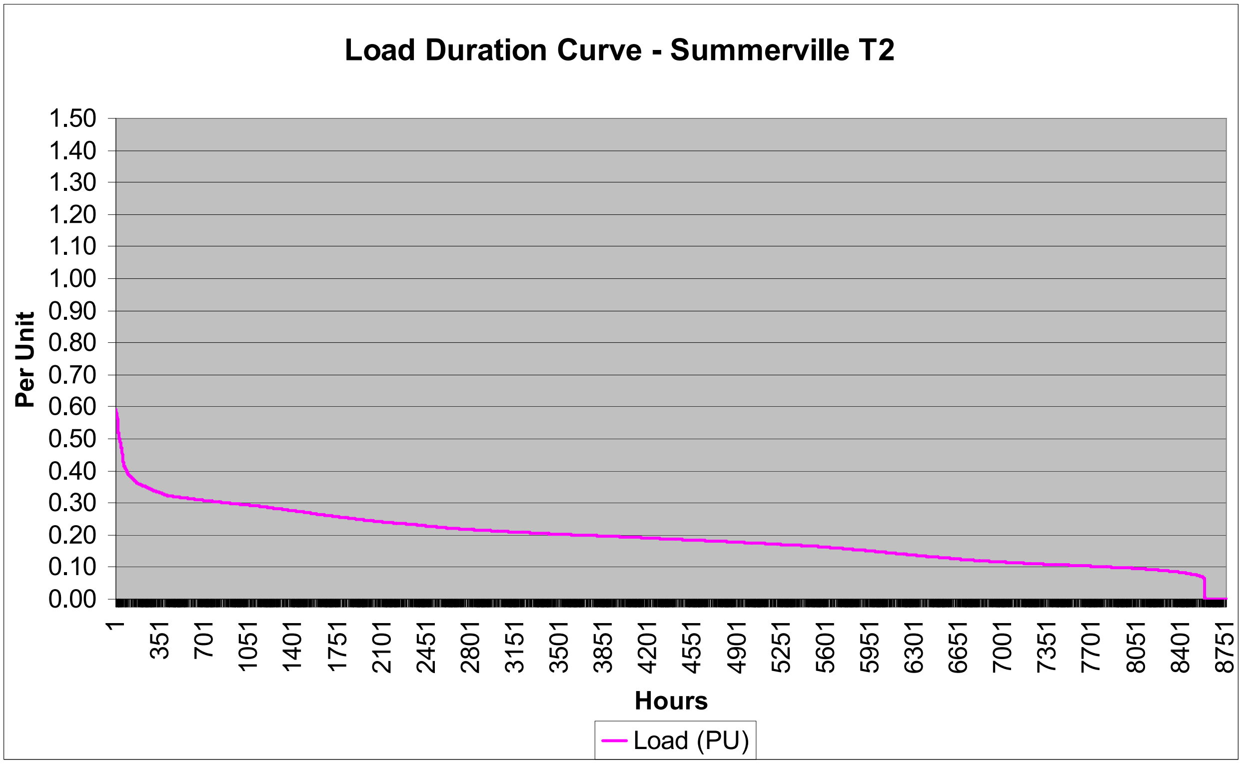



Load Duration Curve - Summerville T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Summerville F4
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

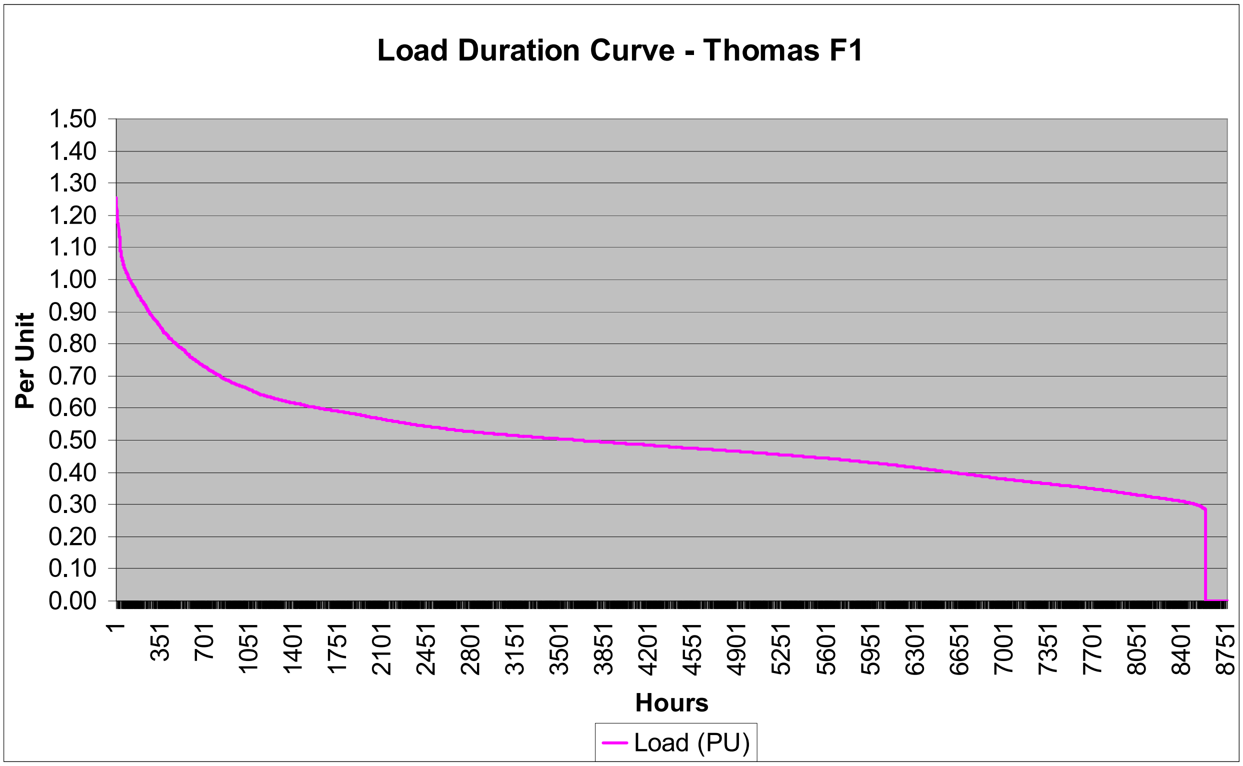


Load Duration Curve - Summerville F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

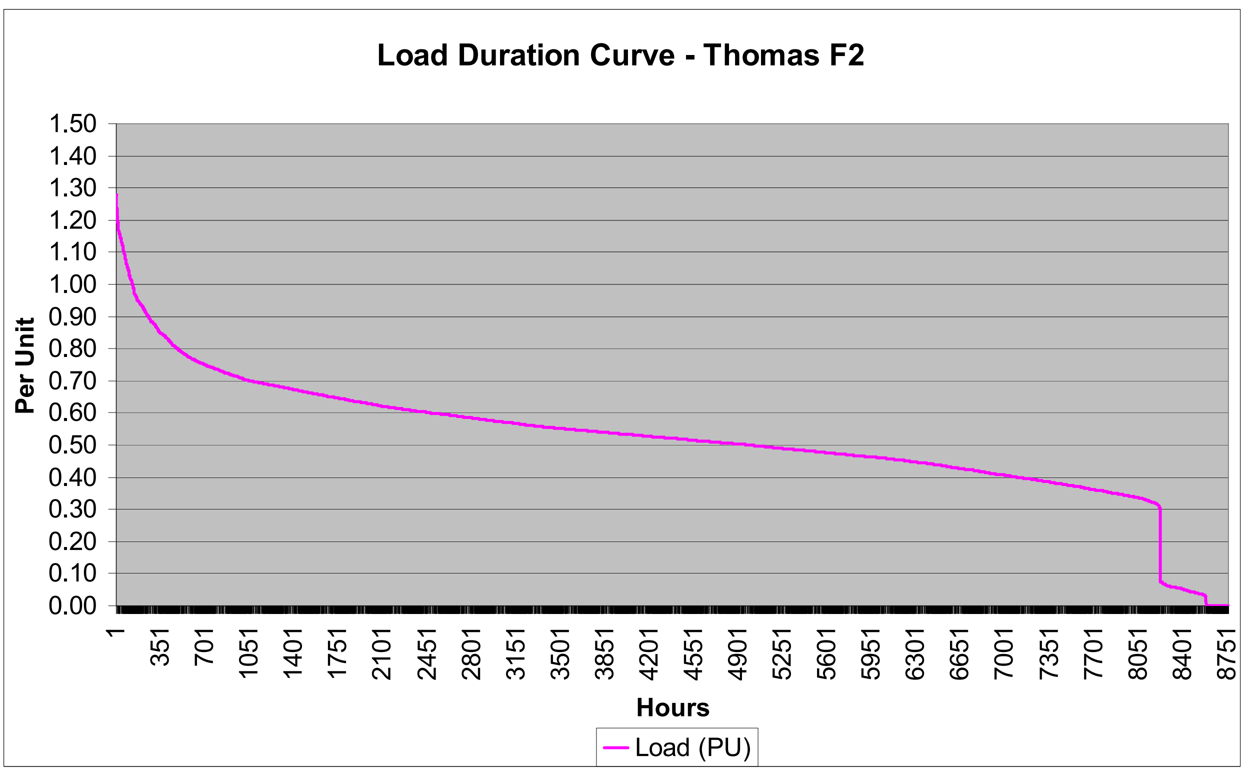


Load Duration Curve - Summerville T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

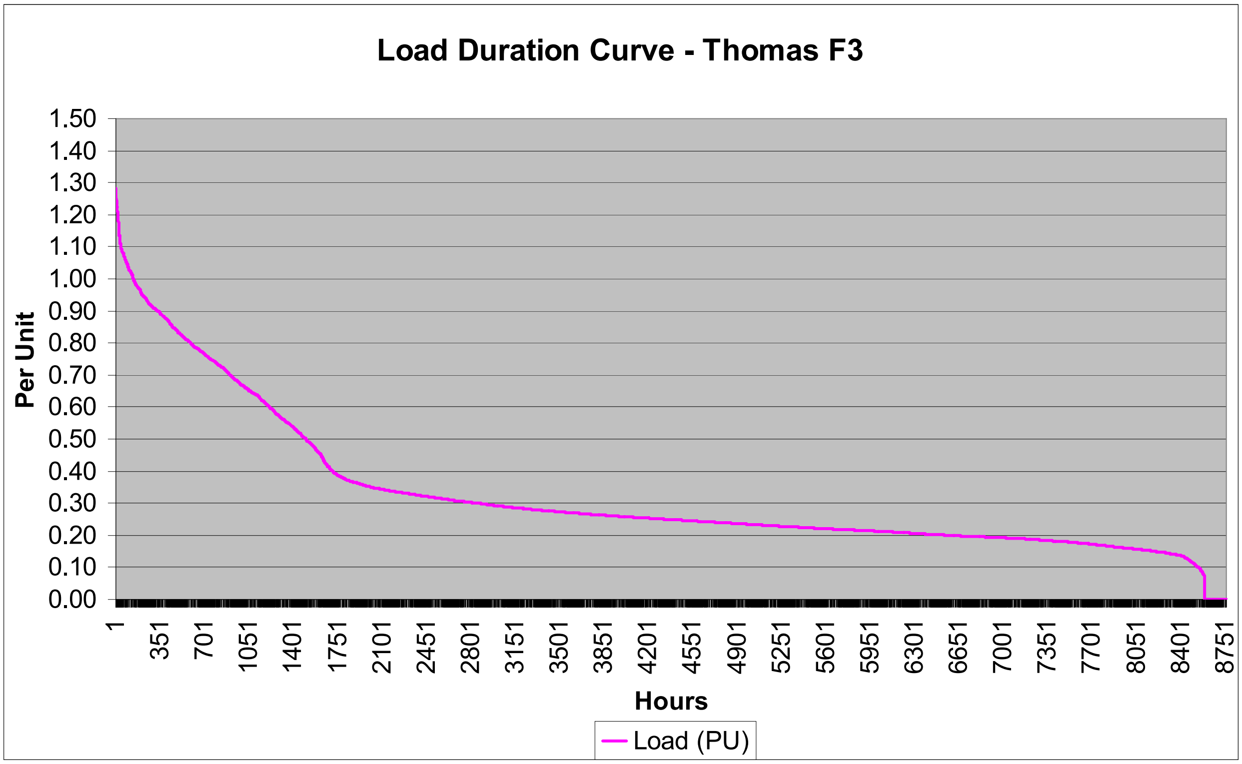
Thomas MS



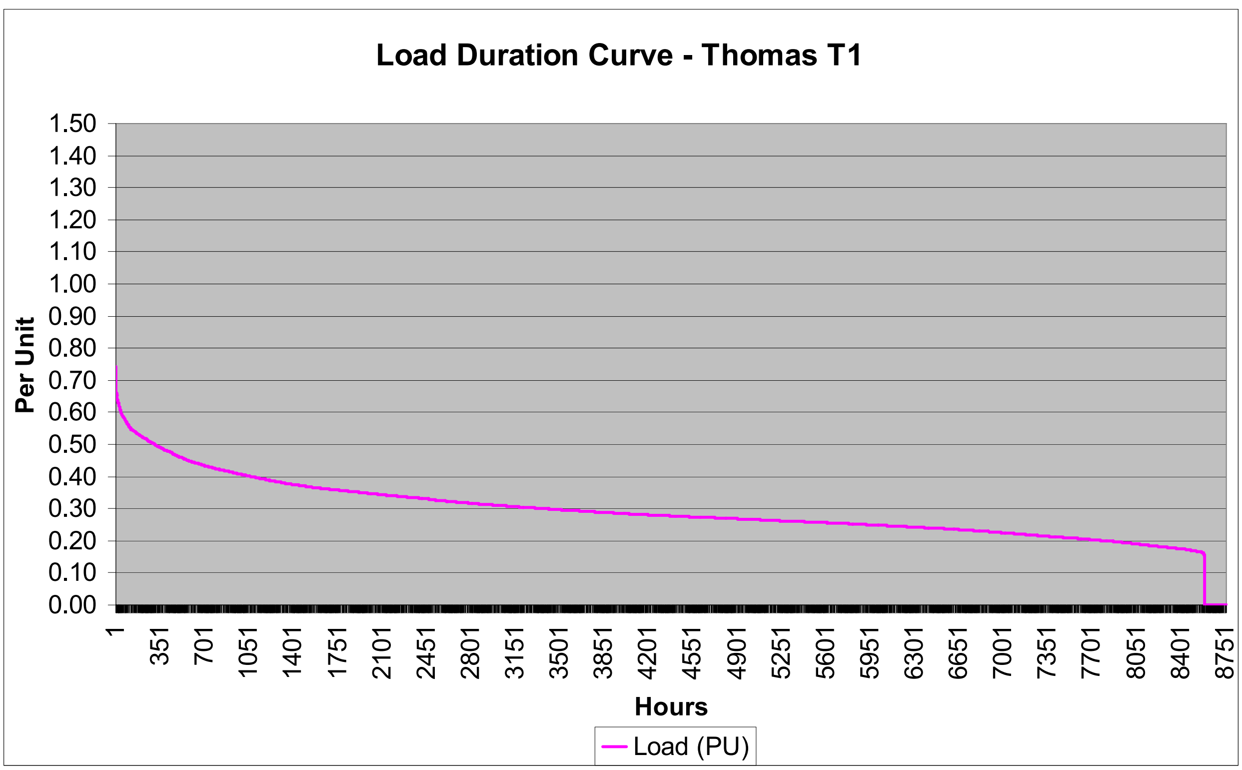
Load Duration Curve - Thomas F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



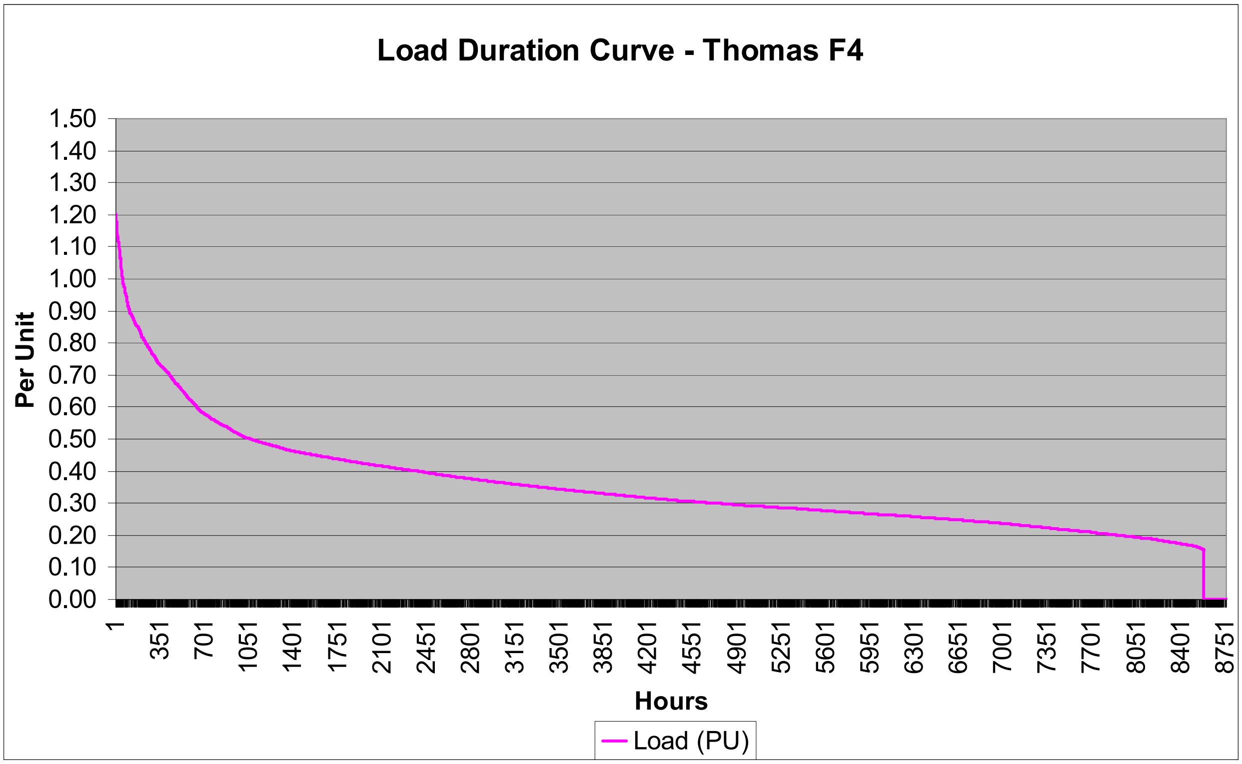
Load Duration Curve - Thomas F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



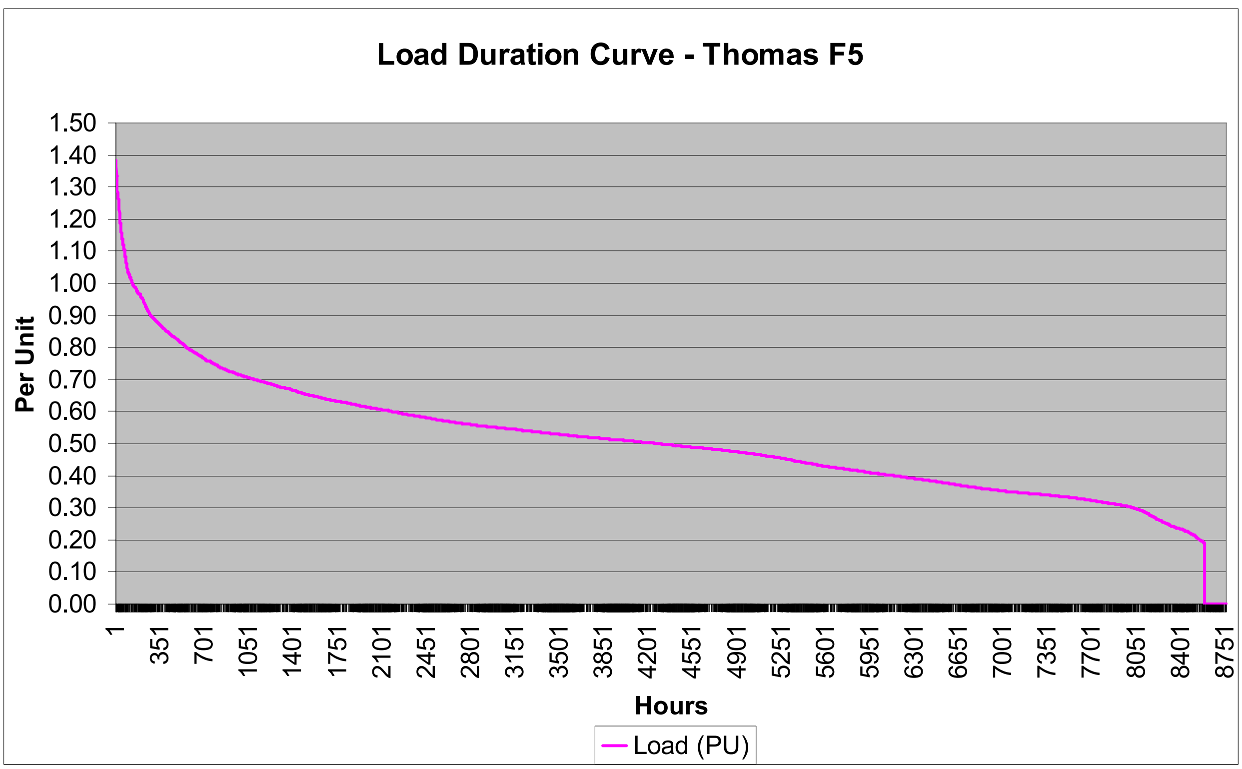
Load Duration Curve - Thomas F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



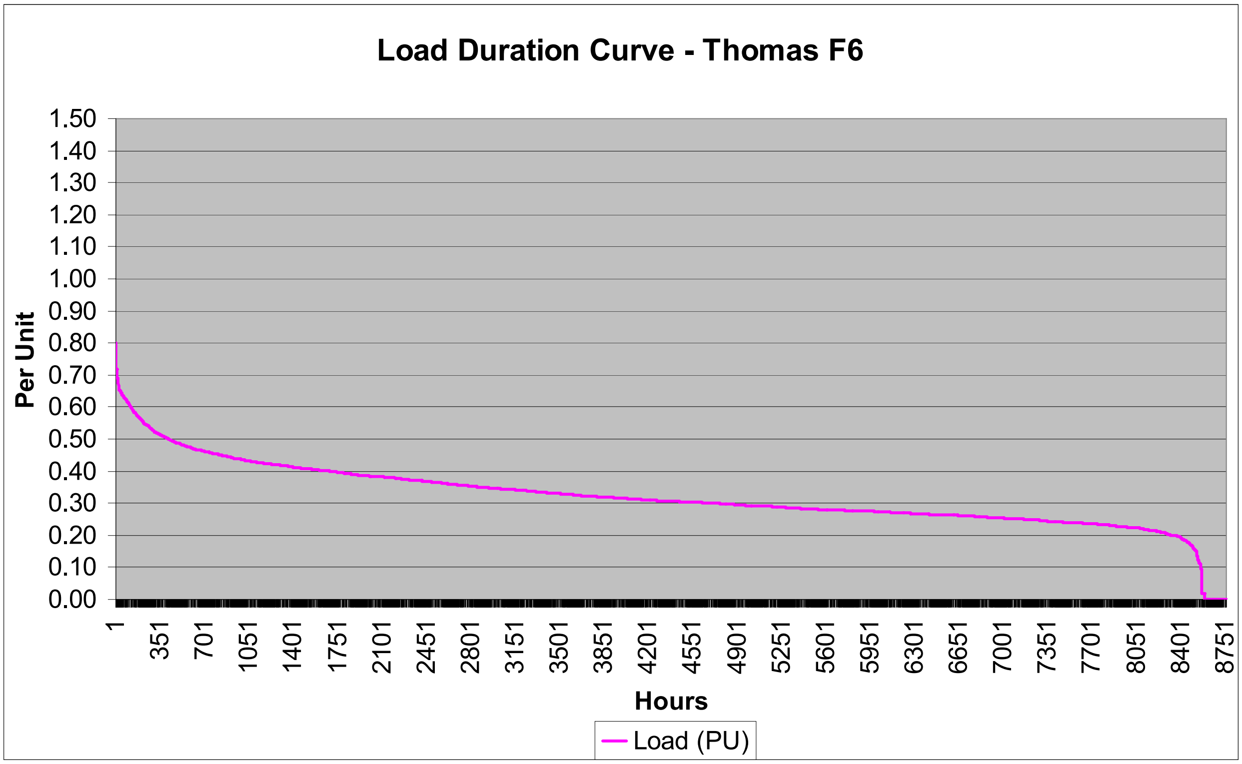
Load Duration Curve - Thomas T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Thomas F4
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Thomas F5
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Thomas F6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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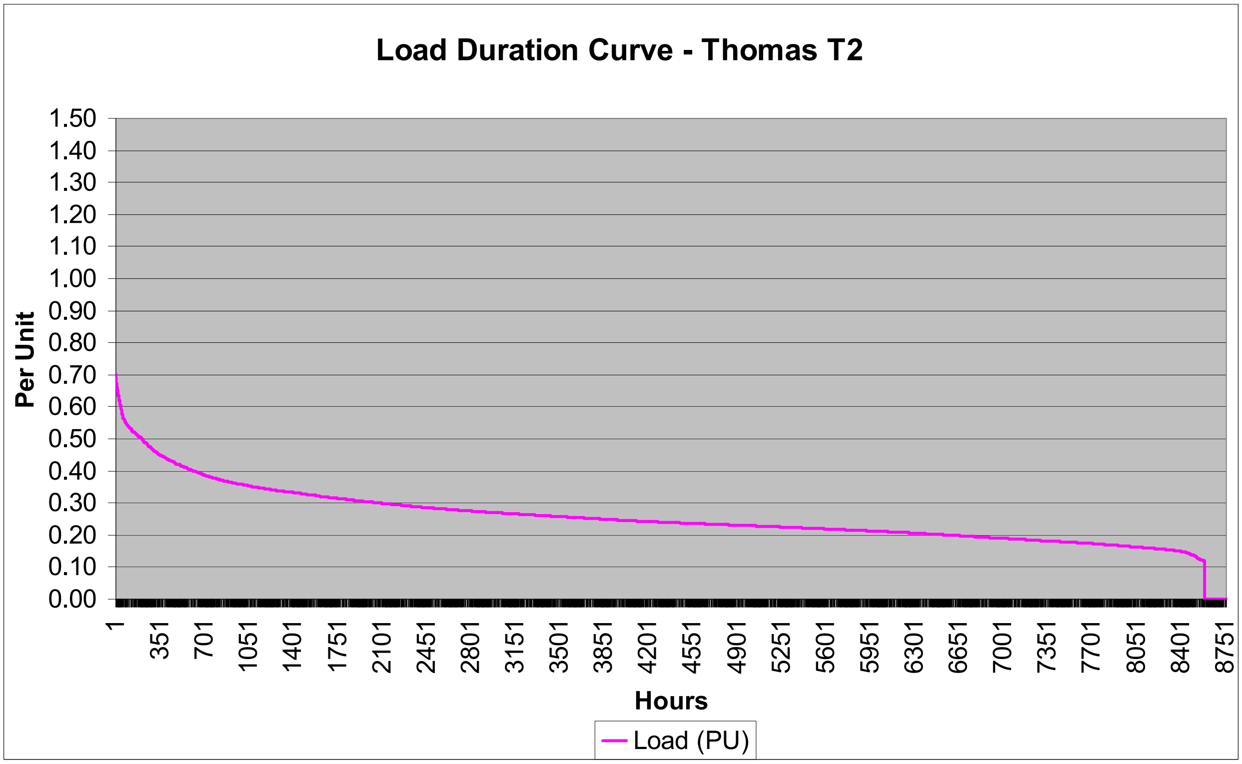
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Thomas T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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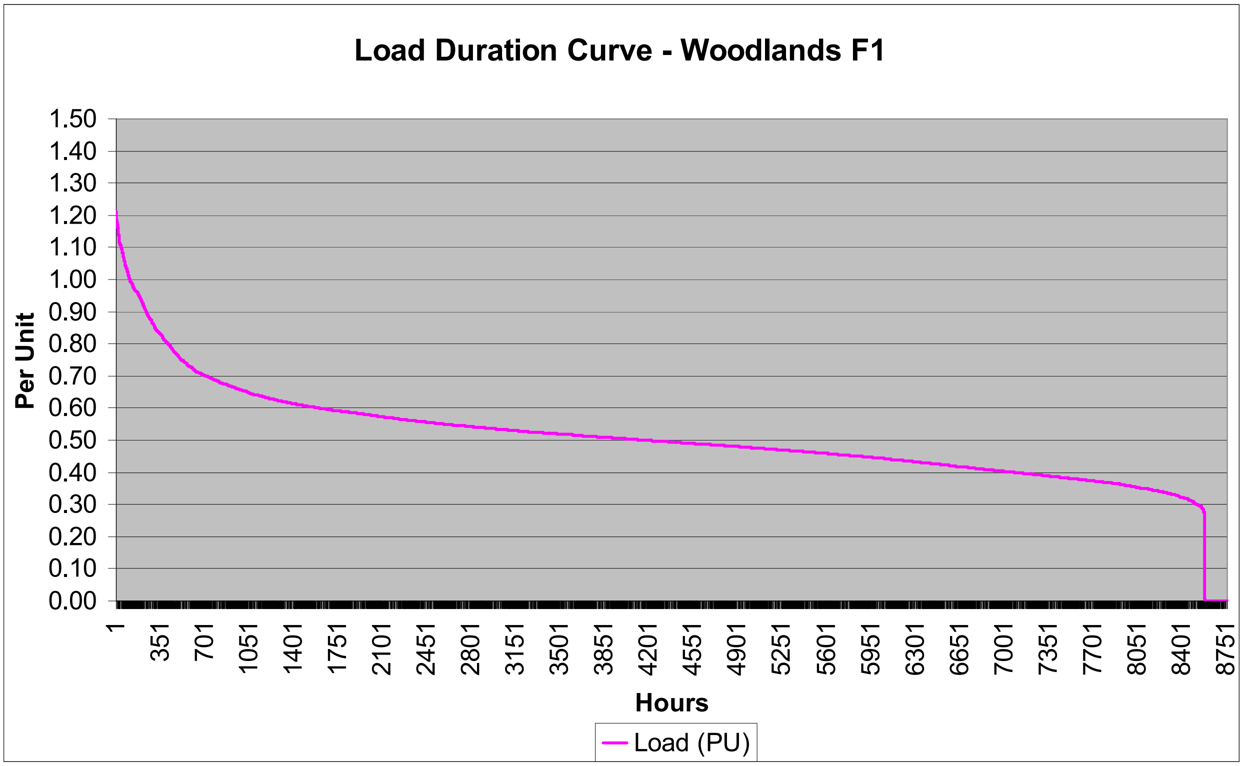
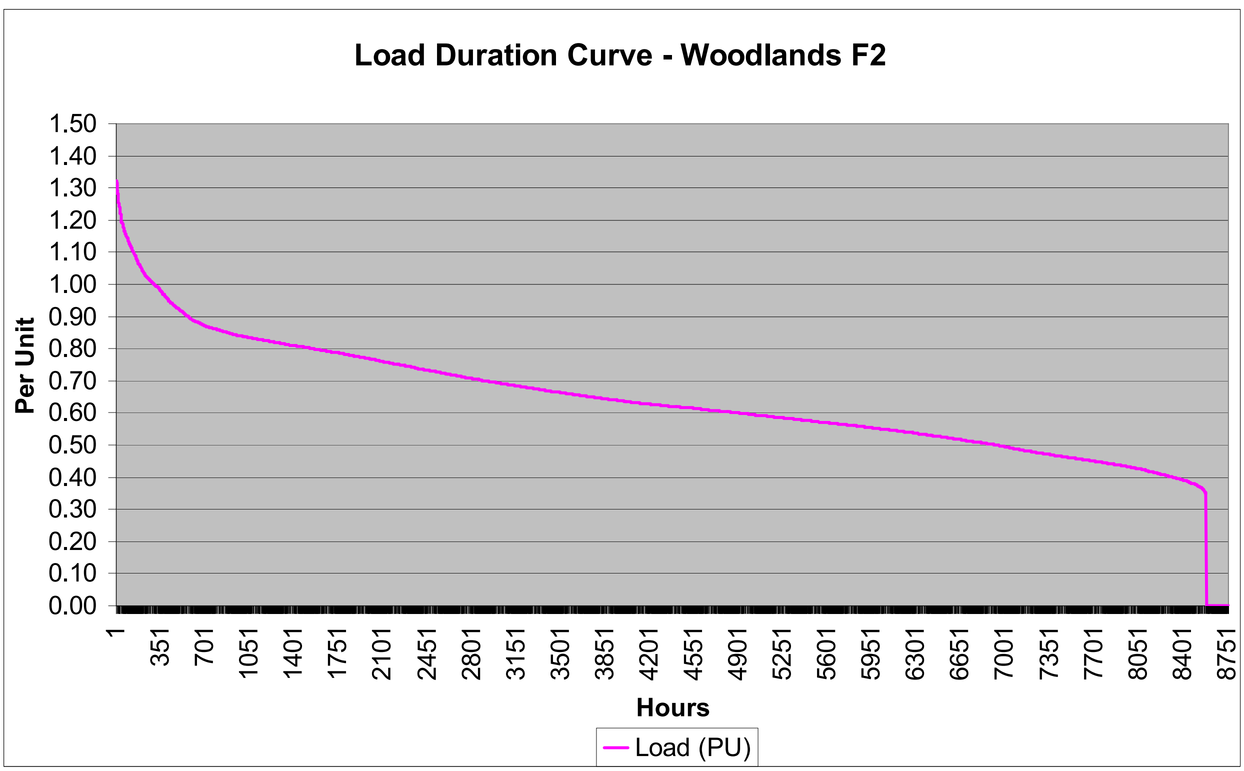
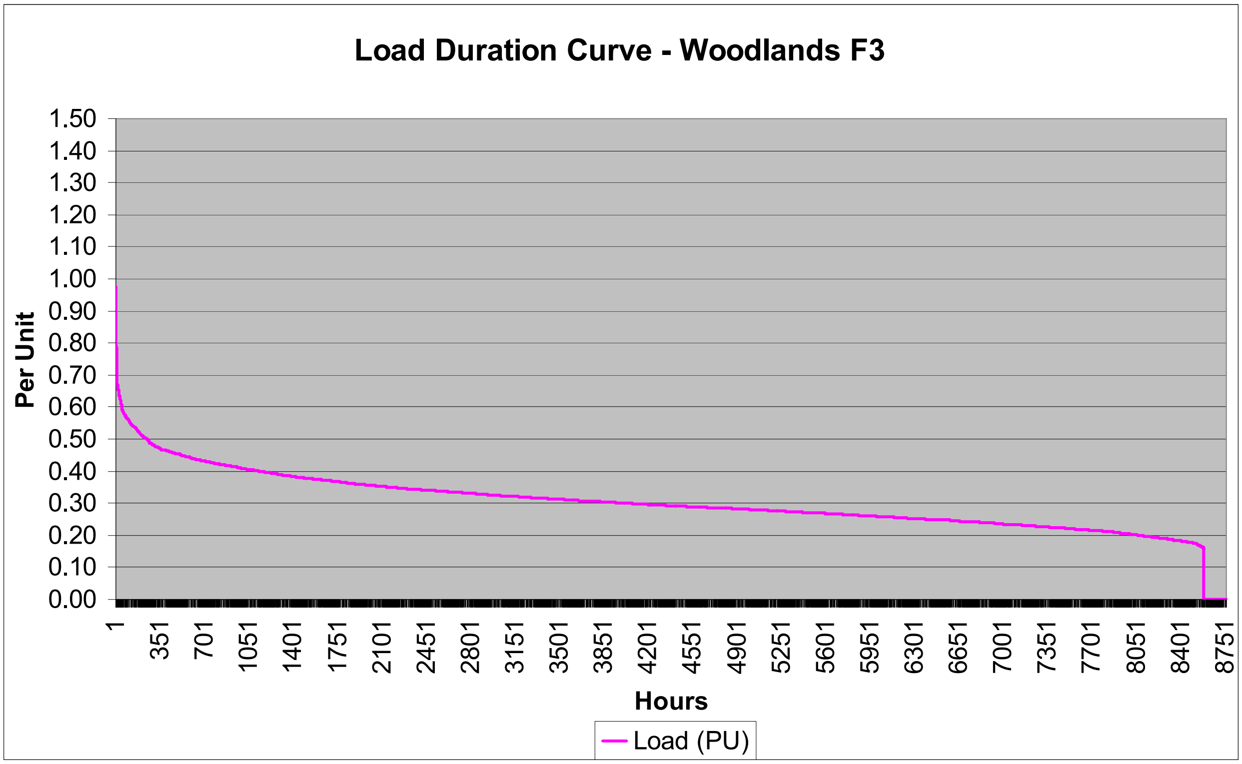
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Woodlands MS






Load Duration Curve - Woodlands F3
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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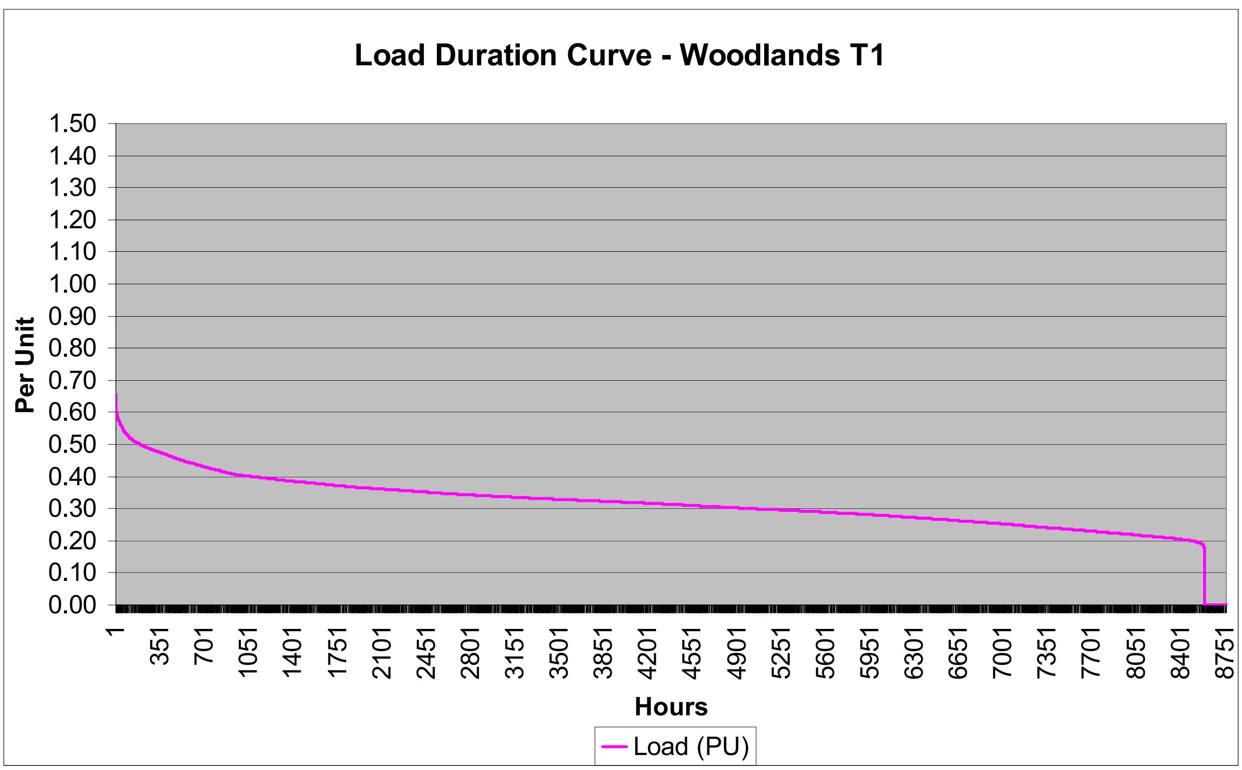
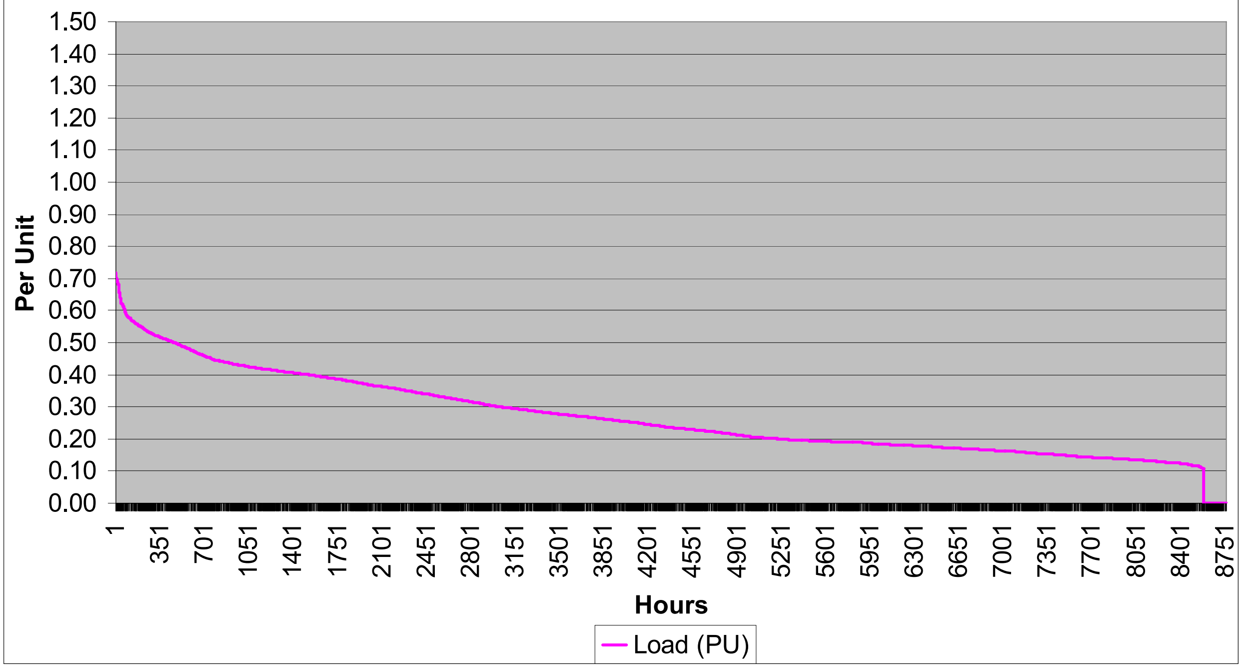
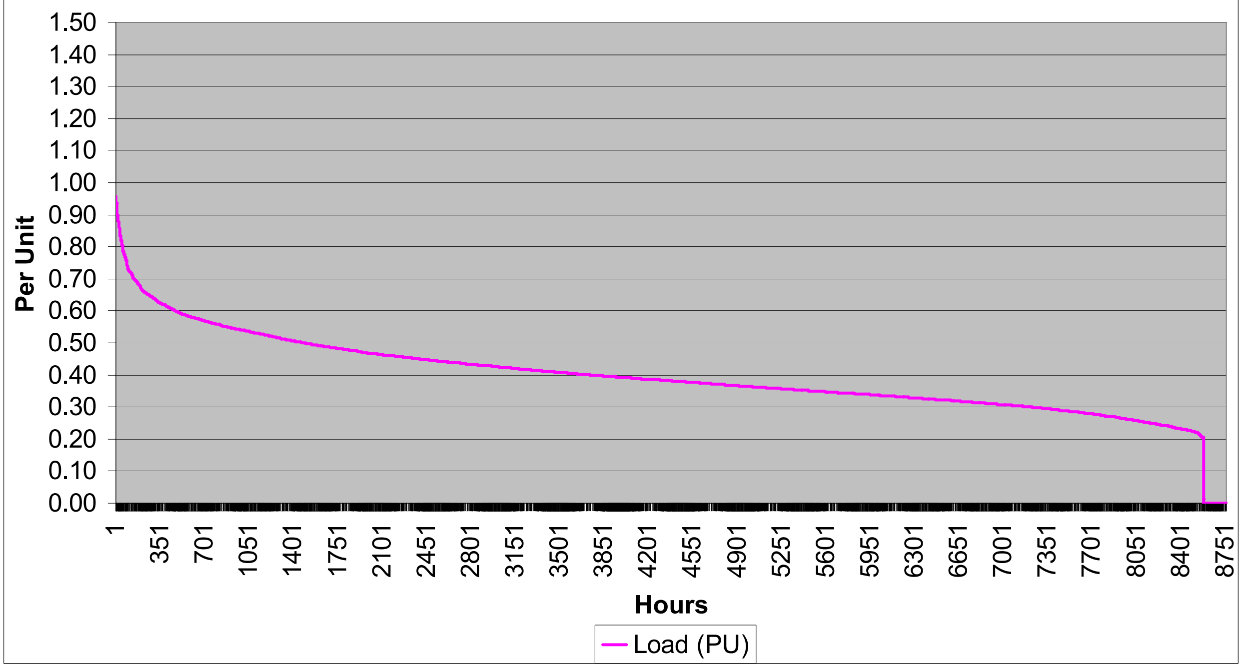
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

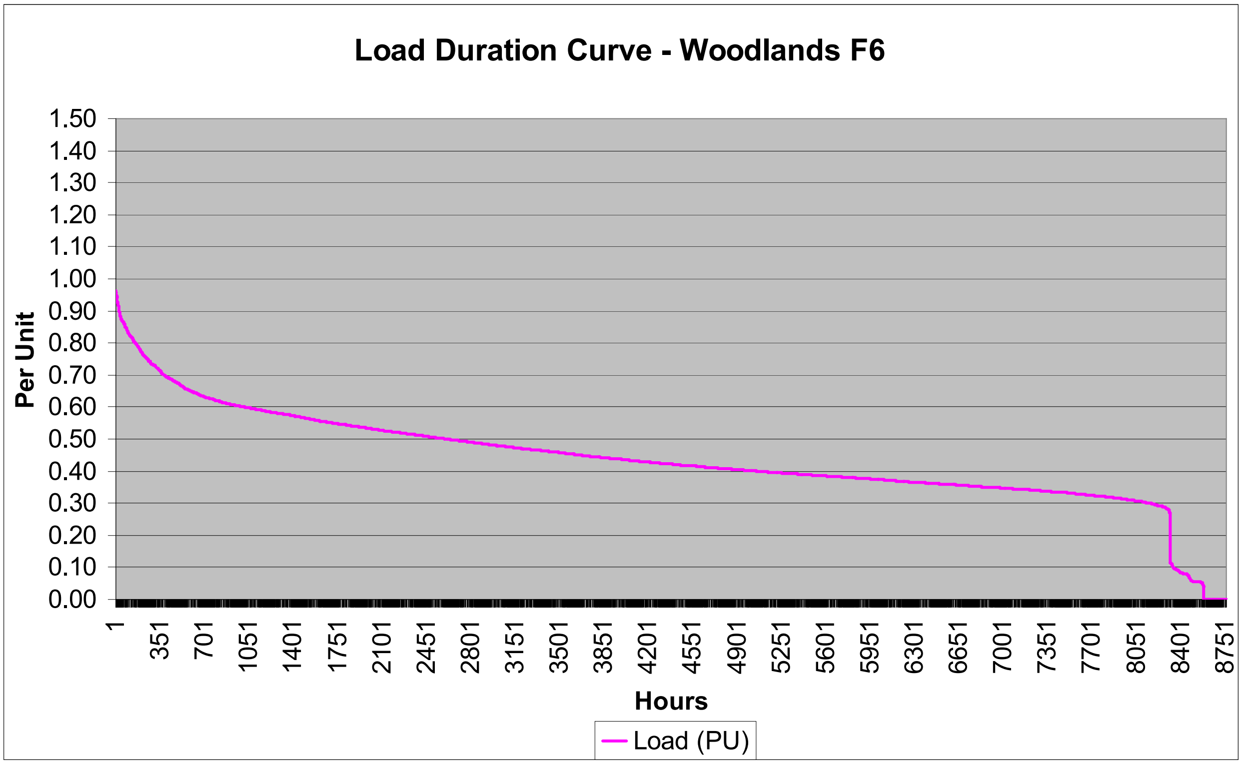

Load Duration Curve - Woodlands T1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

Load Duration Curve - Woodlands F4



Load Duration Curve - Woodlands F5




Load Duration Curve - Woodlands F6
Per Unit
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1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5601
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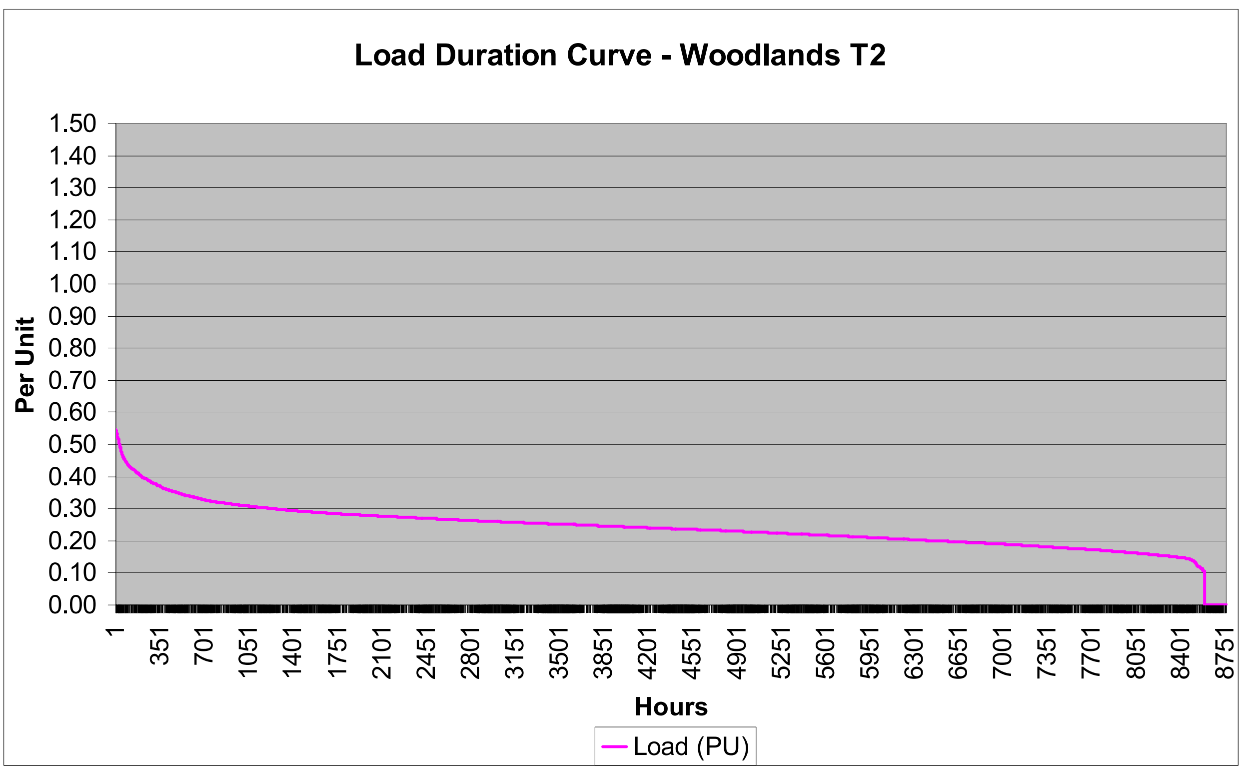
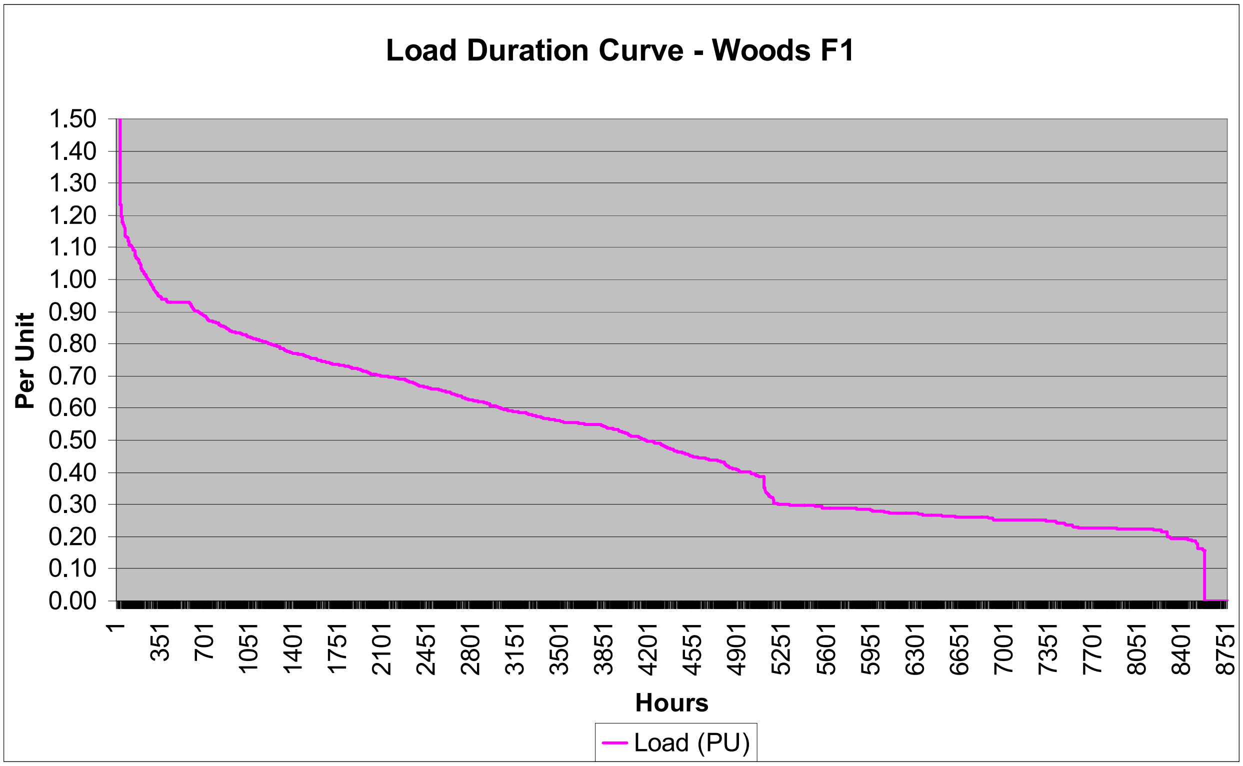
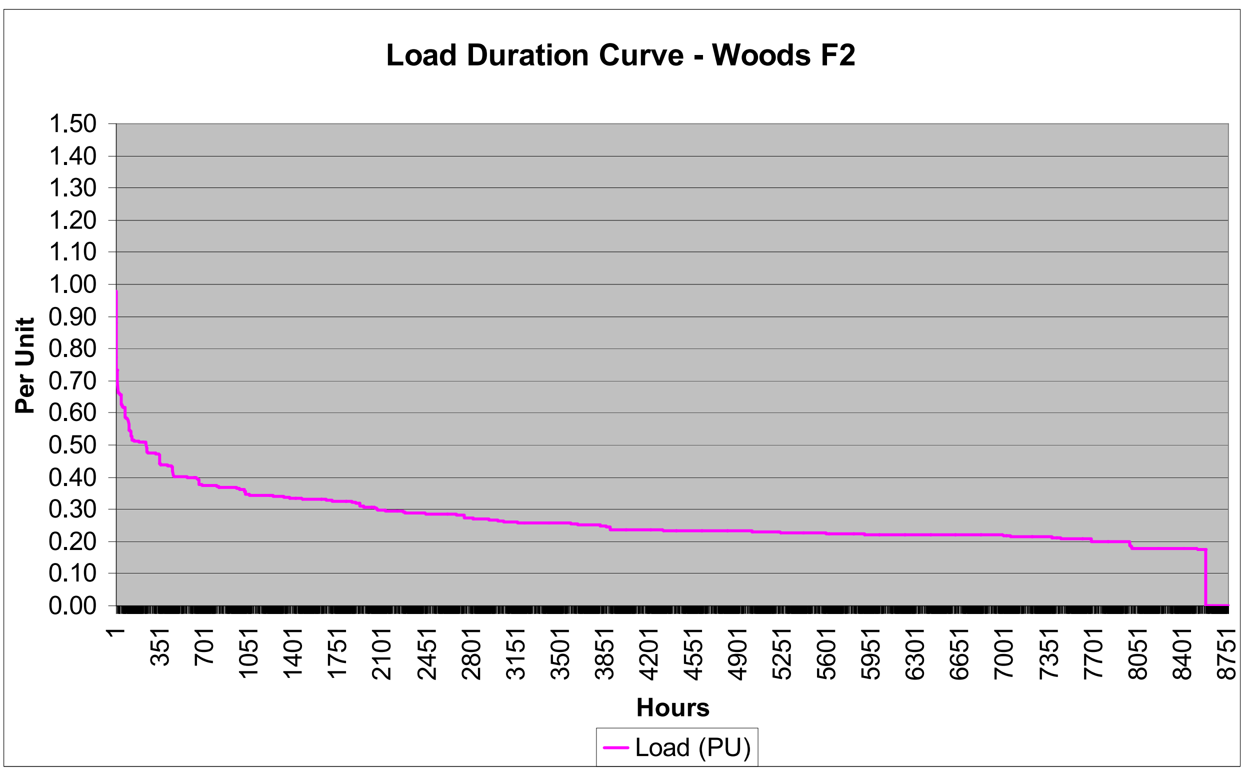
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Woodlands T2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

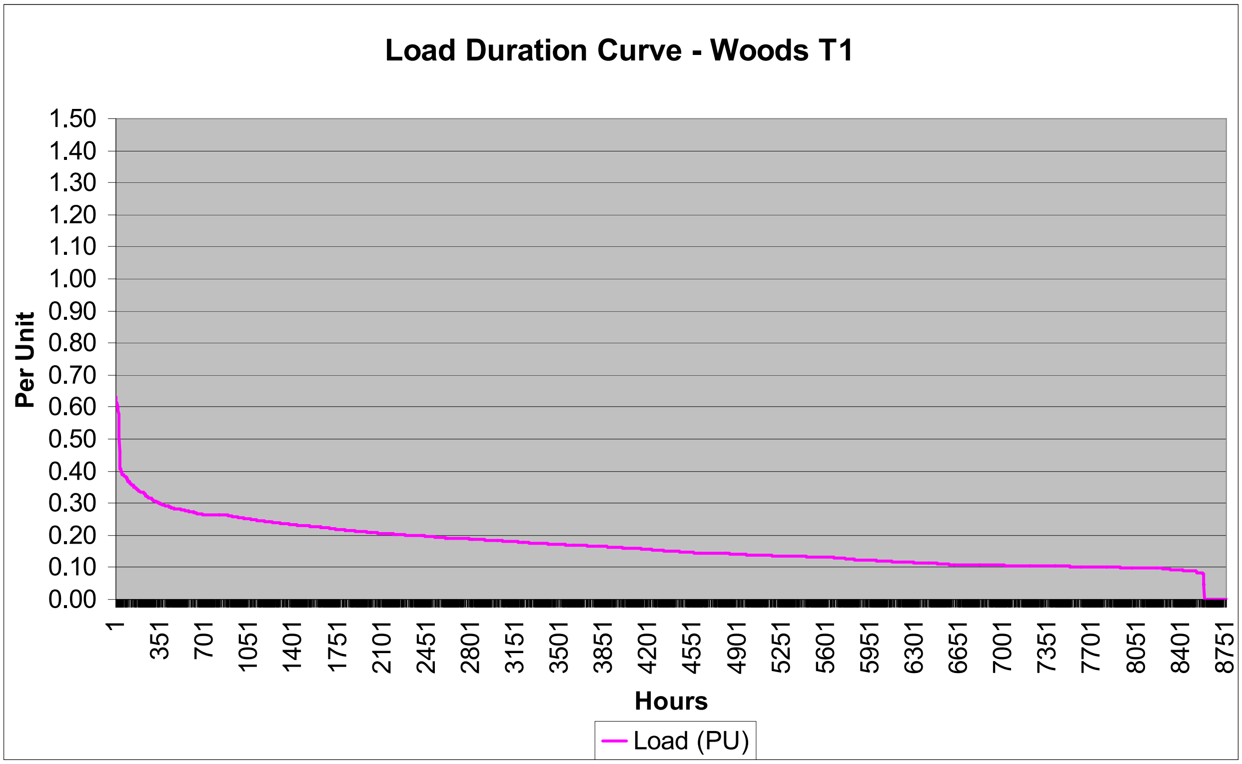
Woods MS

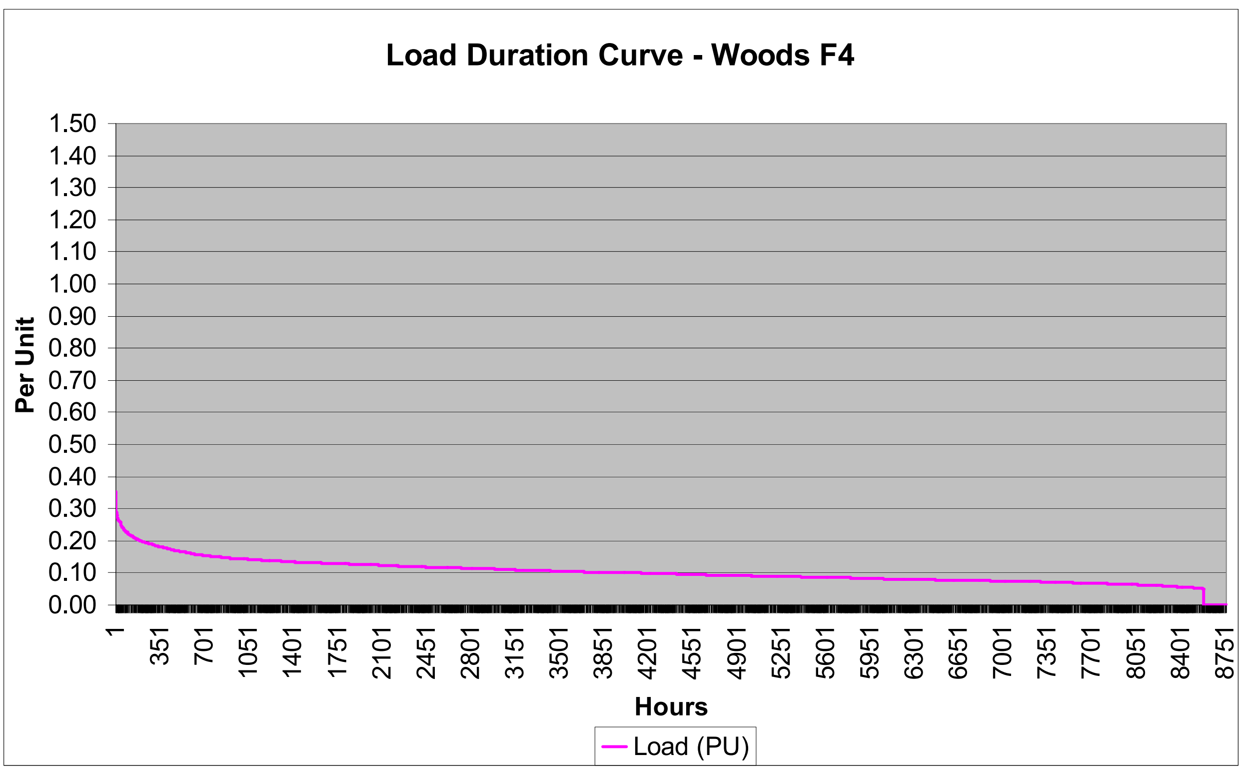


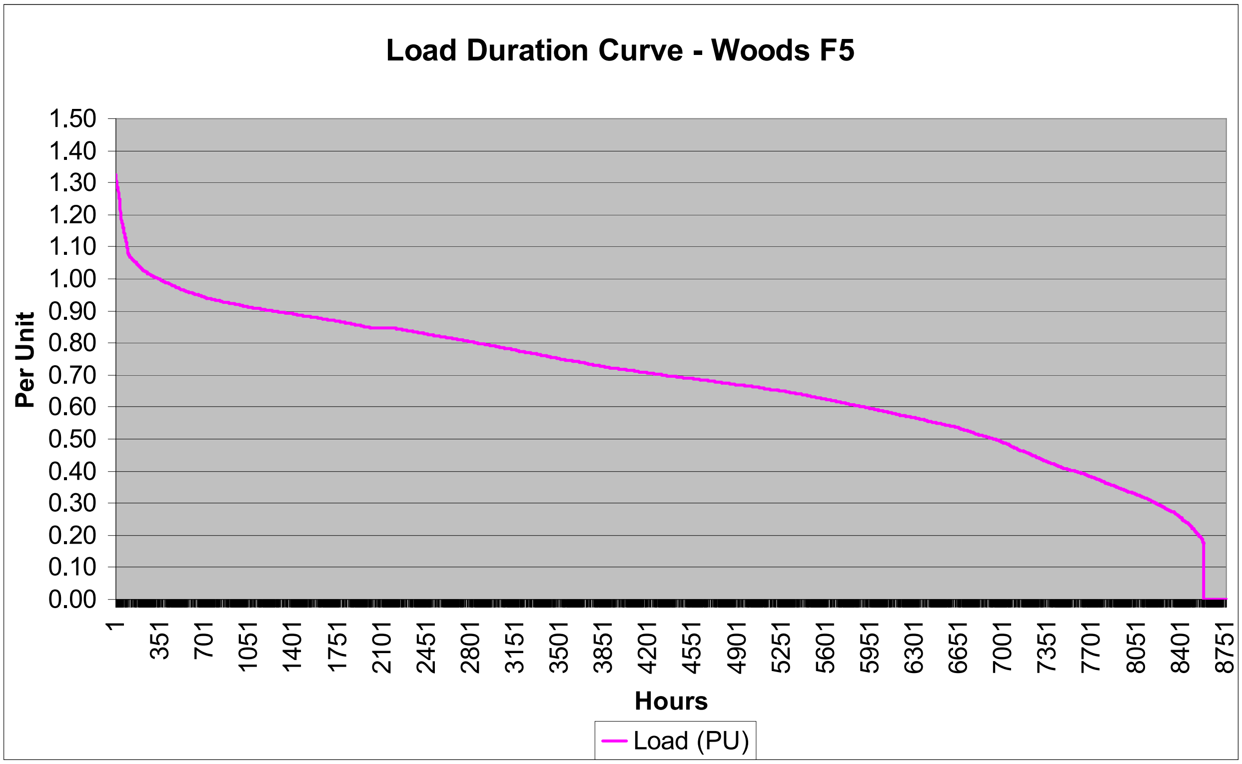
Load Duration Curve - Woods F1
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



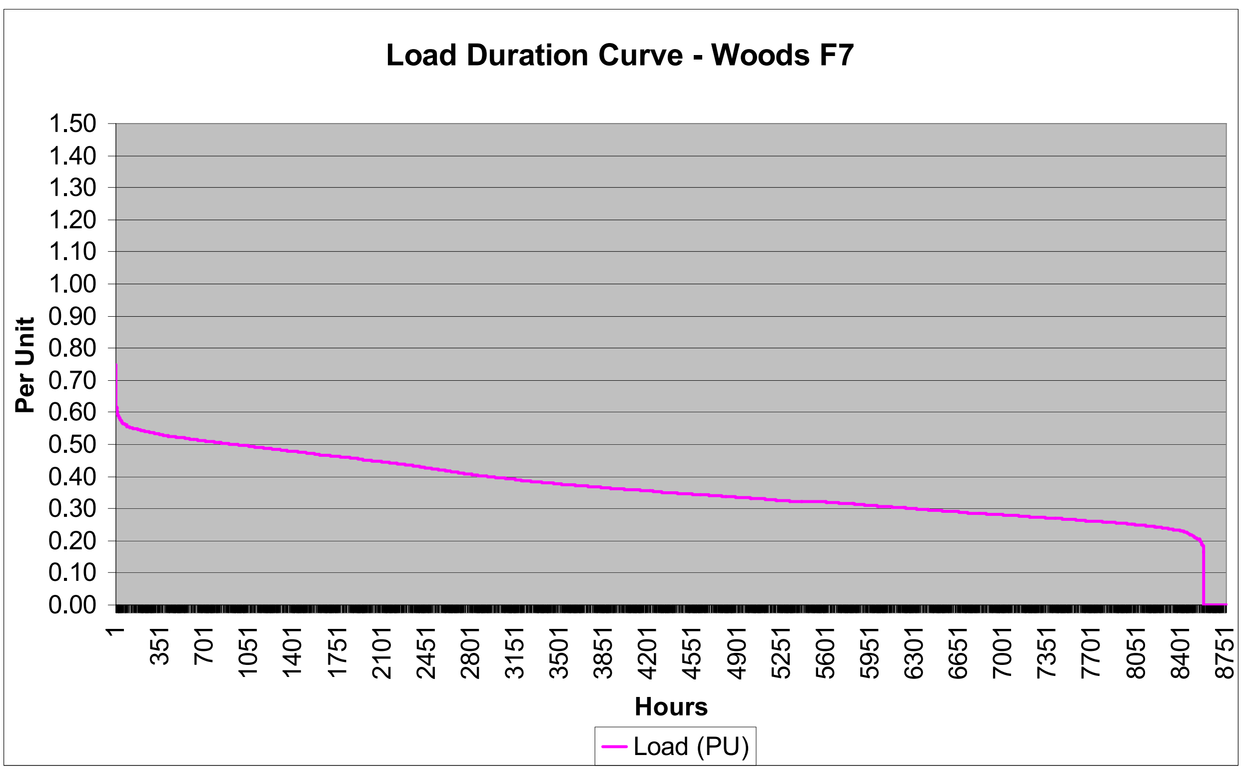
Load Duration Curve - Woods F2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Woods T1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Woods F4
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Woods F5
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Woods F7
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
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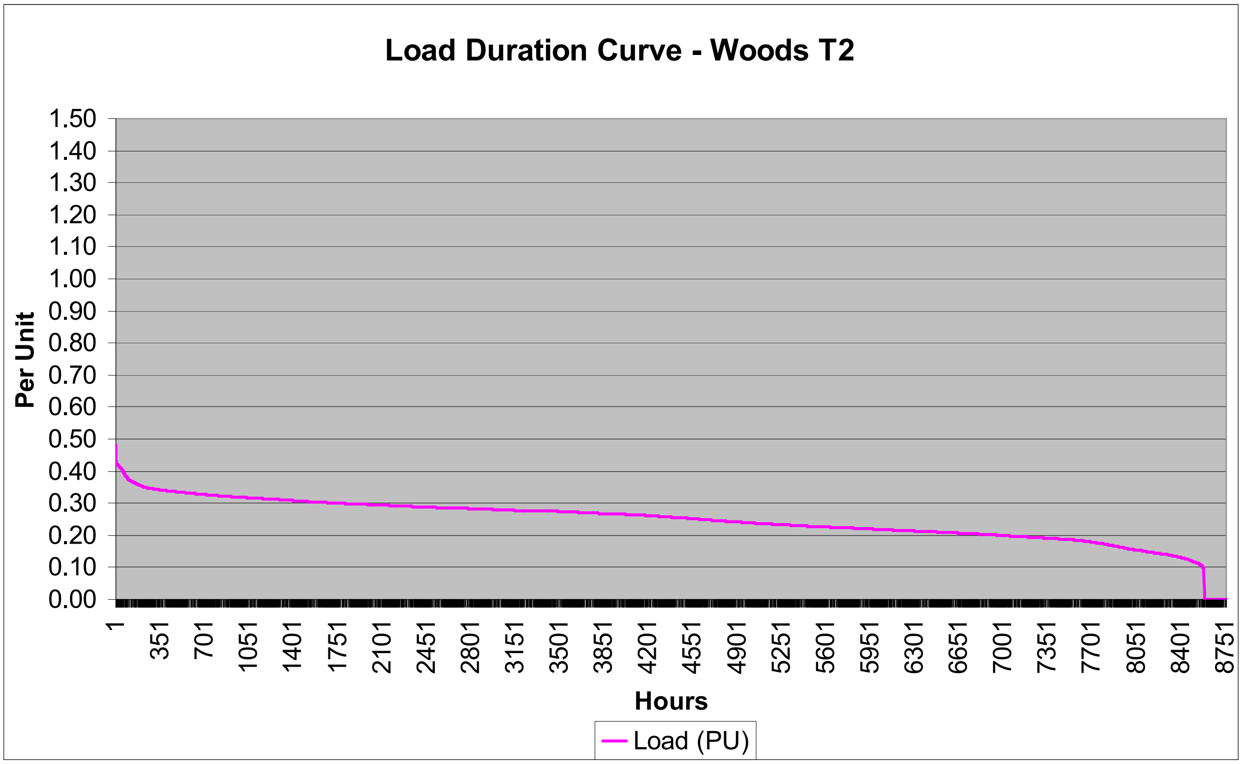
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Woods T2
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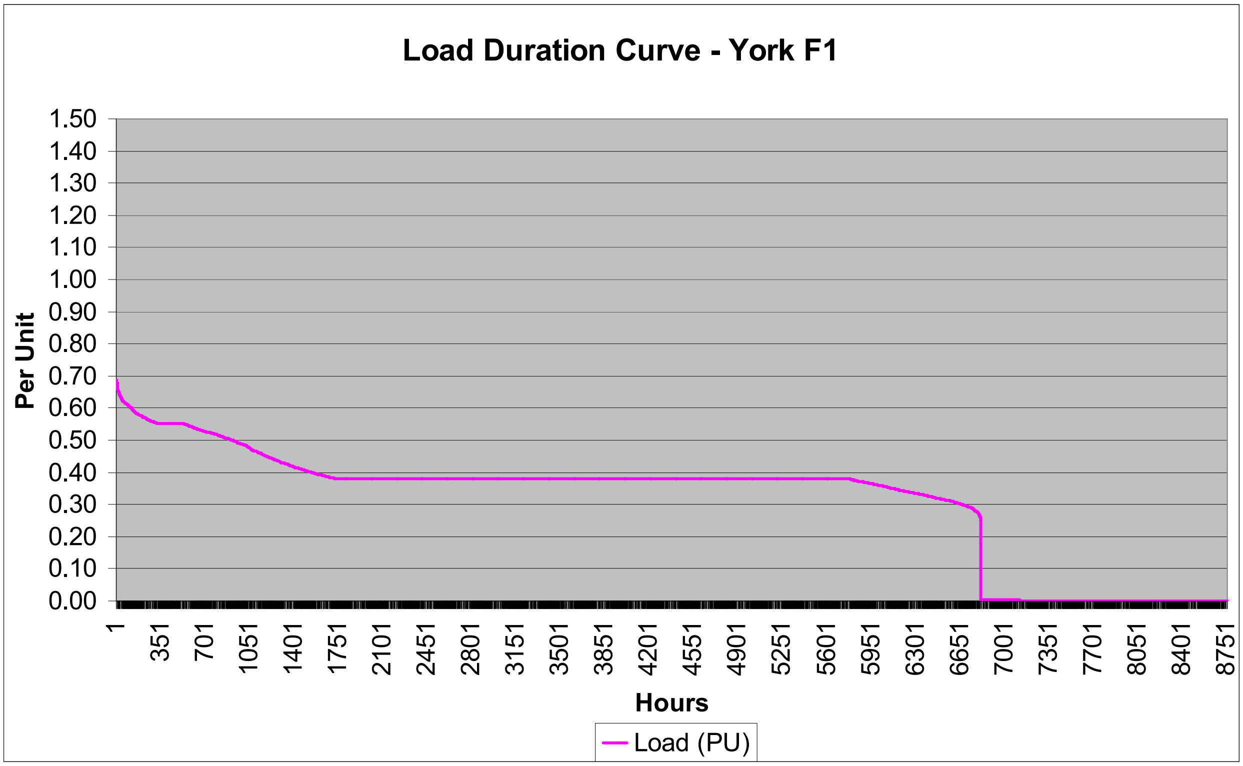
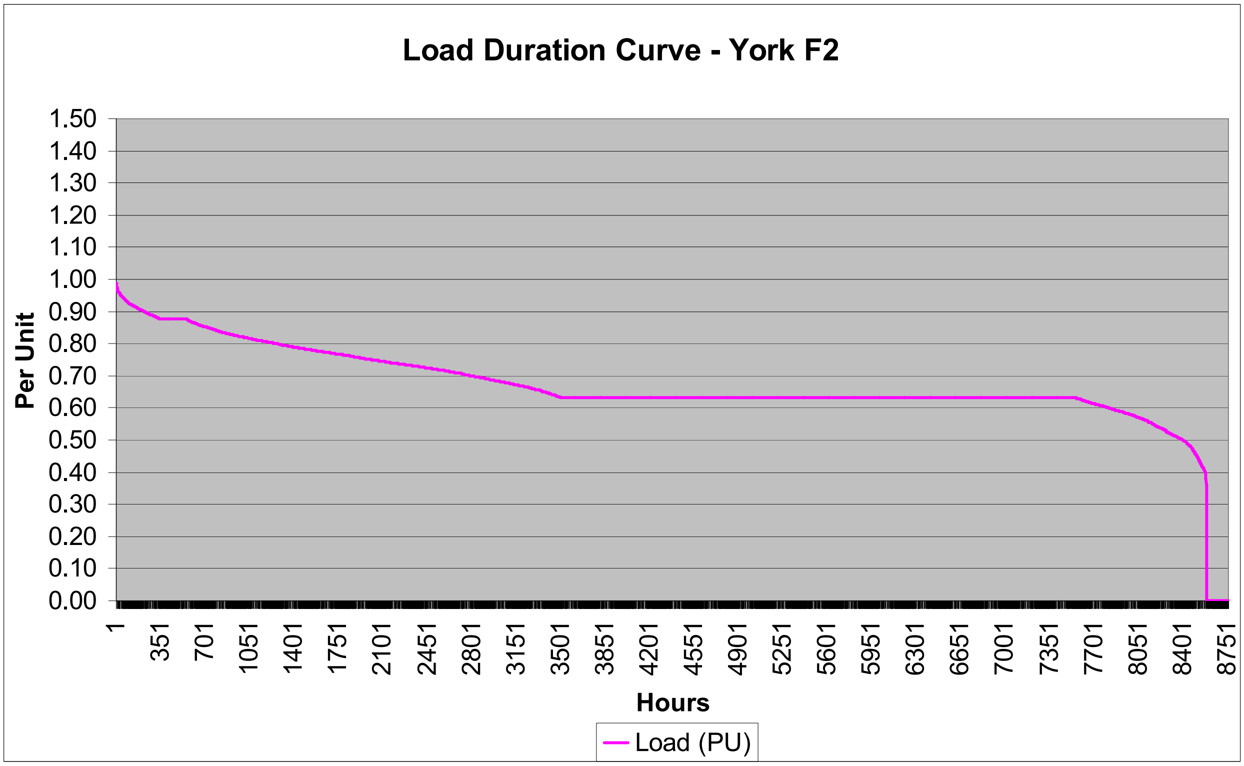
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

York MS



Load Duration Curve - York F1
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - York F2
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1.40
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1.00
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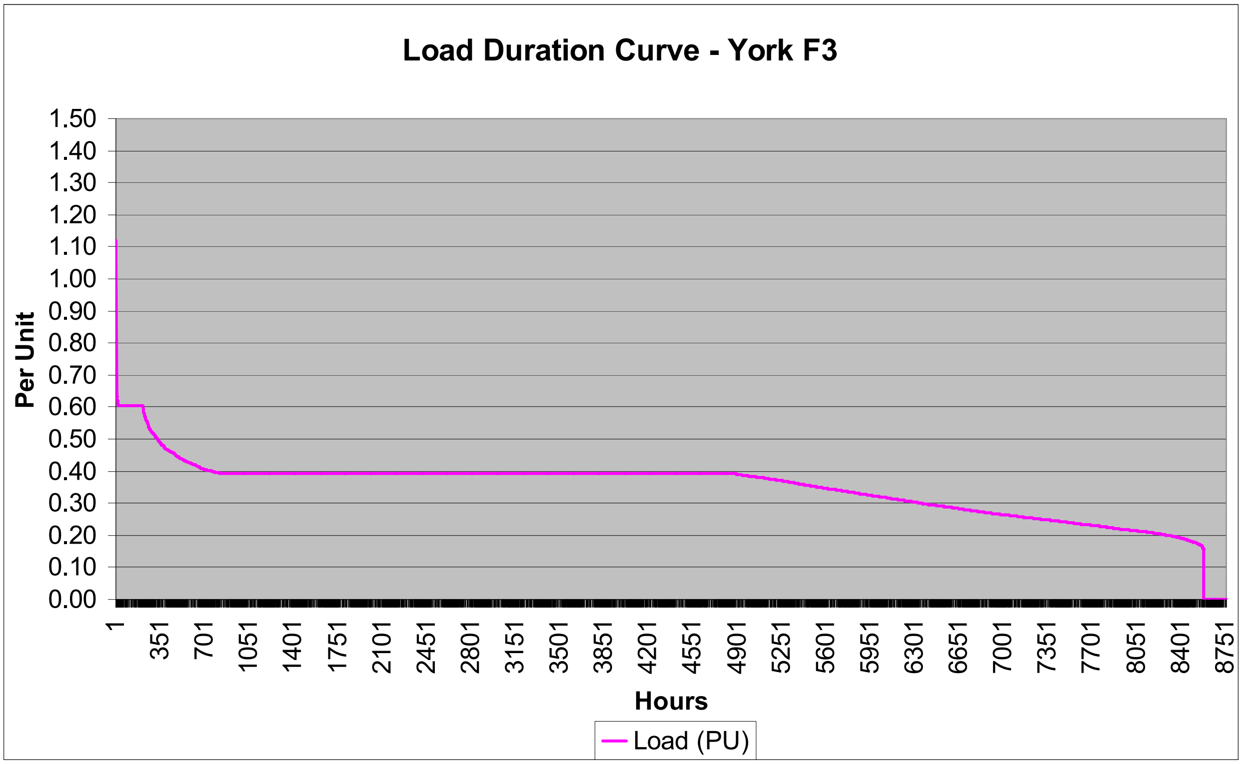
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - York F3
Per Unit
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1.40
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1.10
1.00
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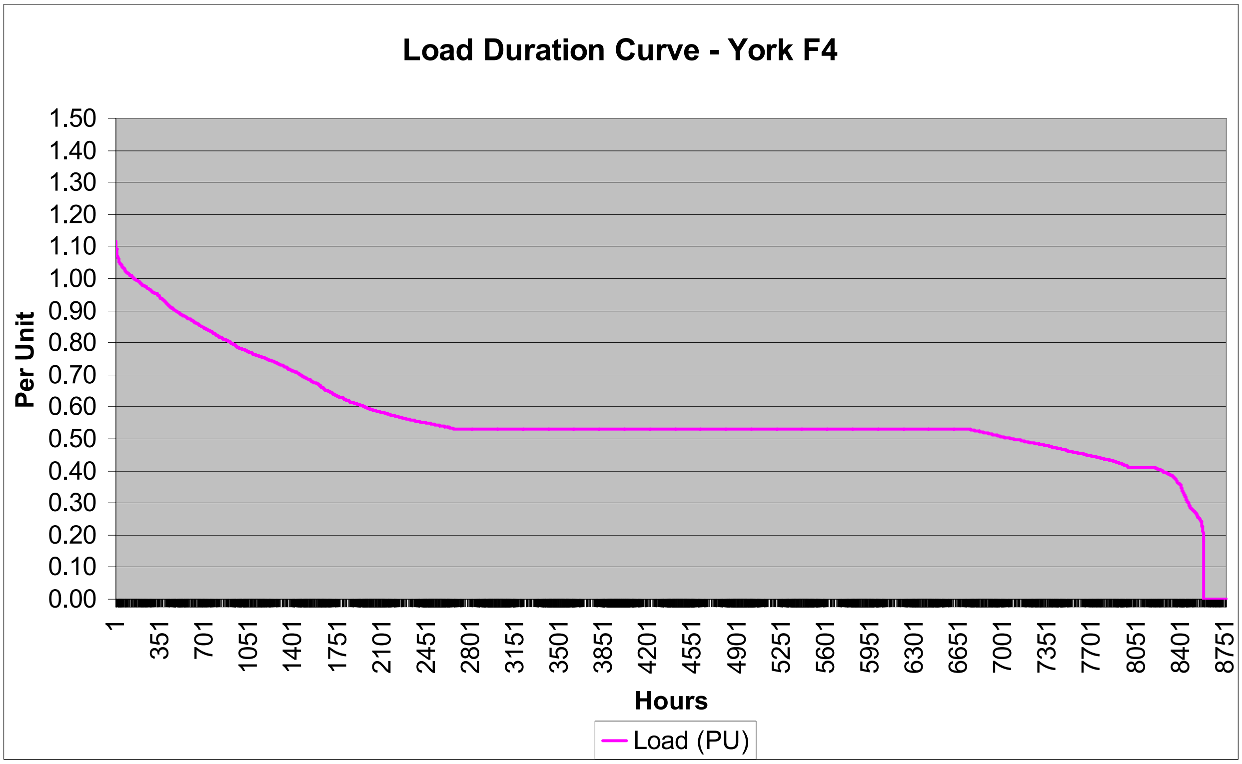
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - York F4
Per Unit
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1.40
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1.10
1.00
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
5601
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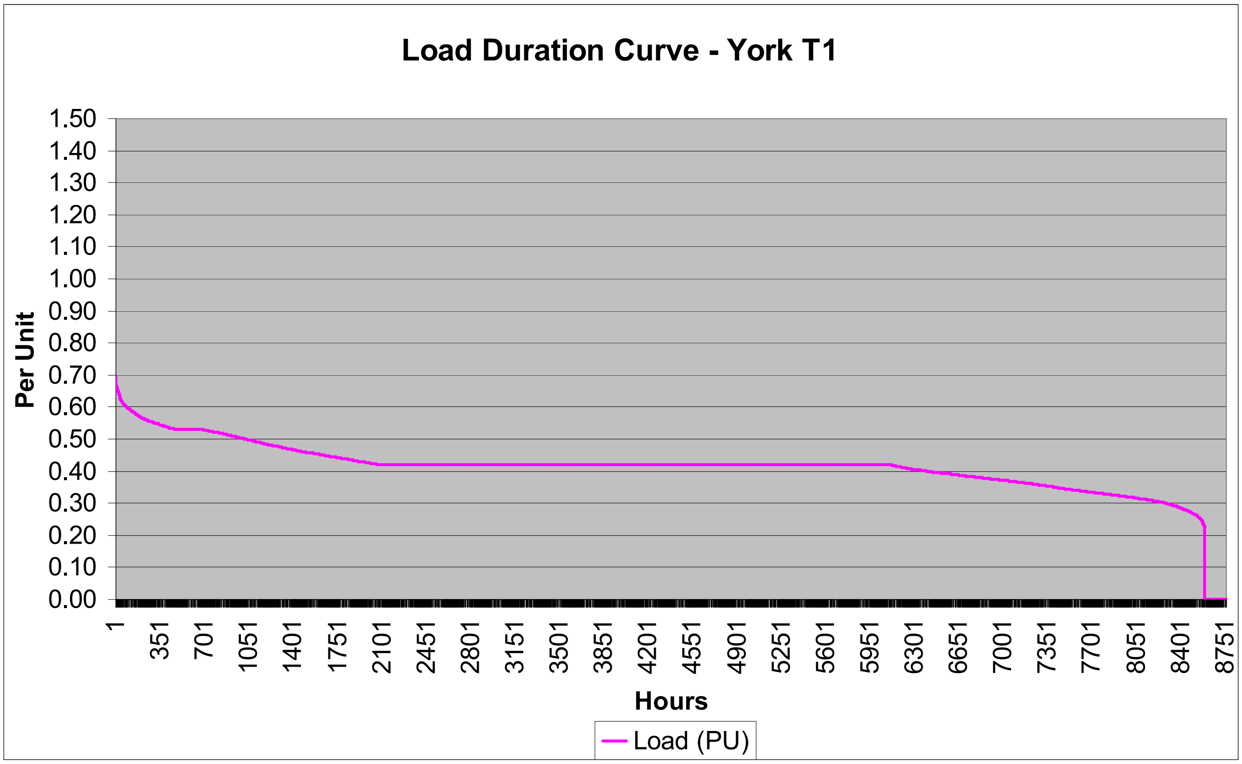
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - York T1
Per Unit
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1.40
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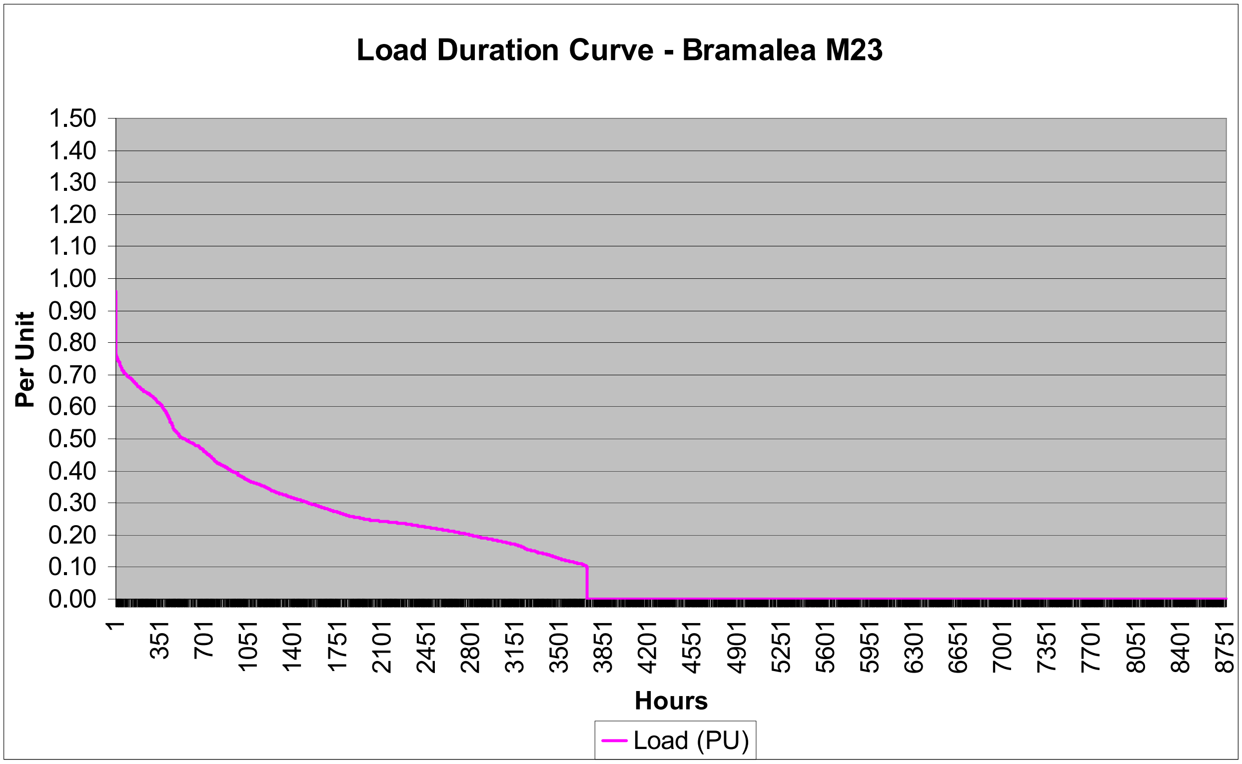
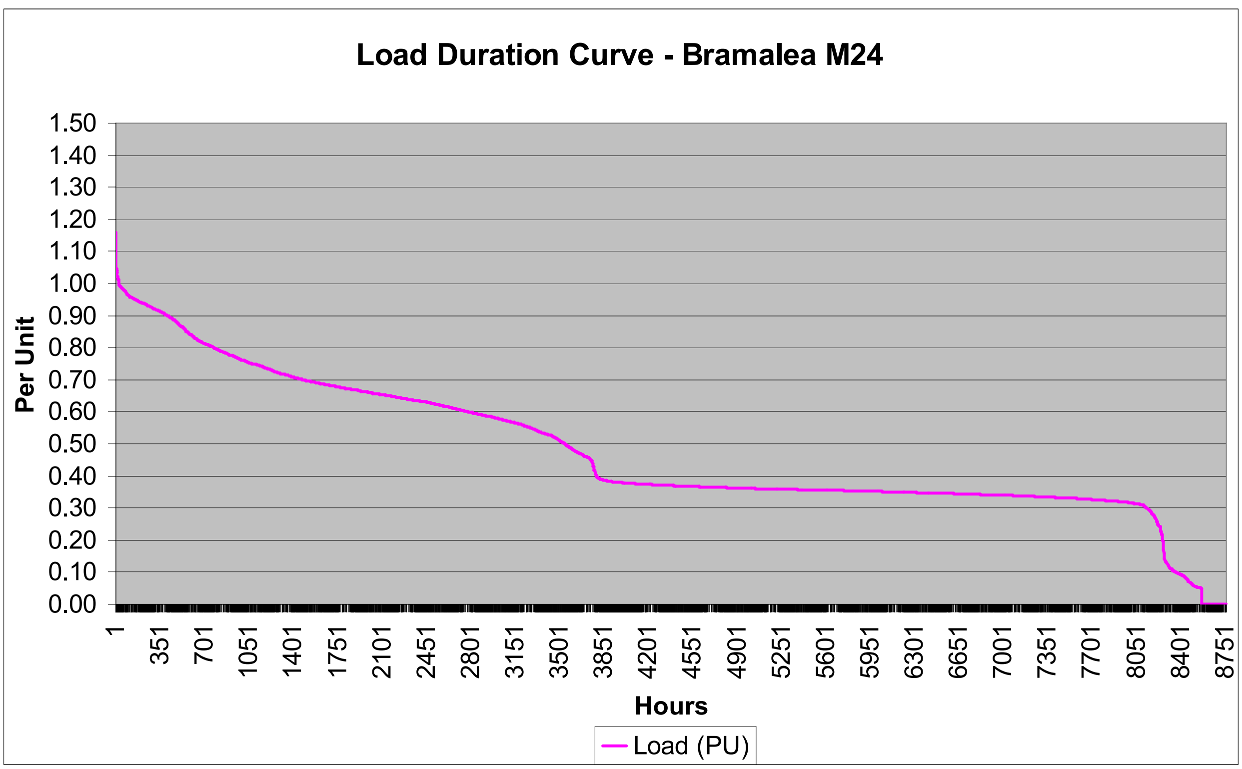
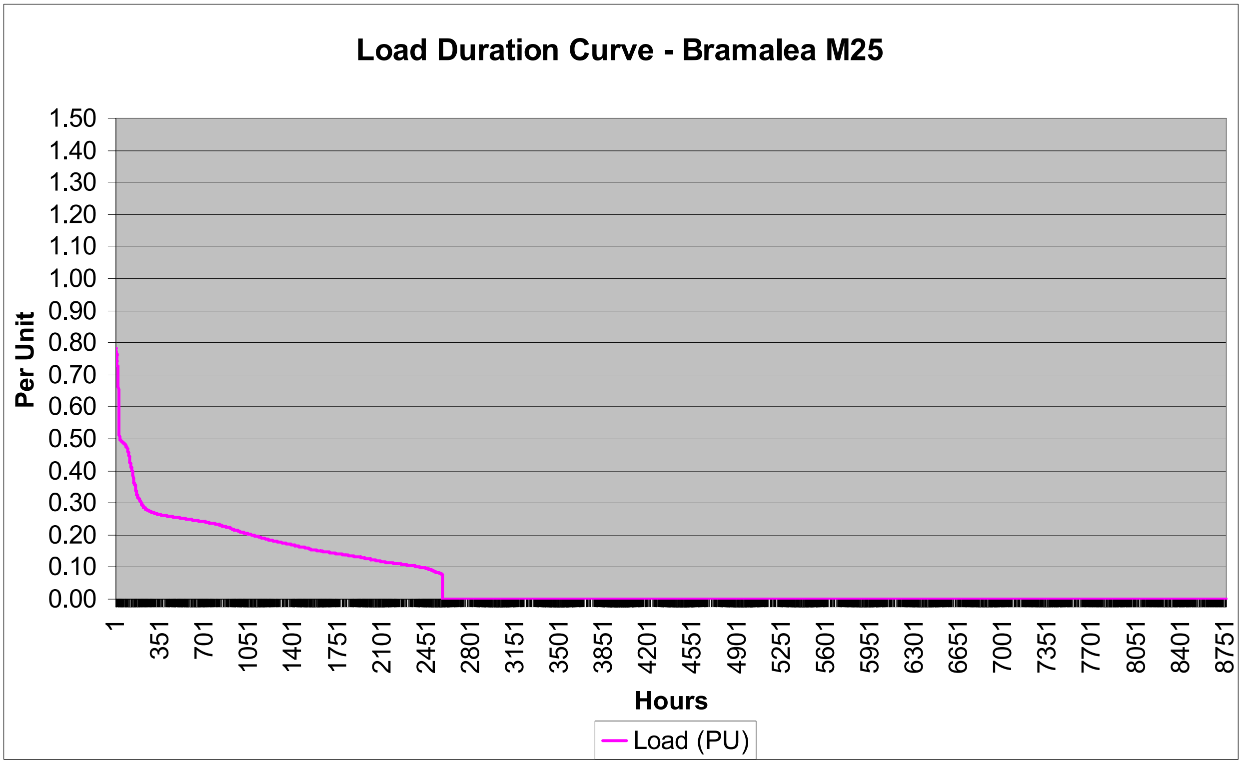
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)

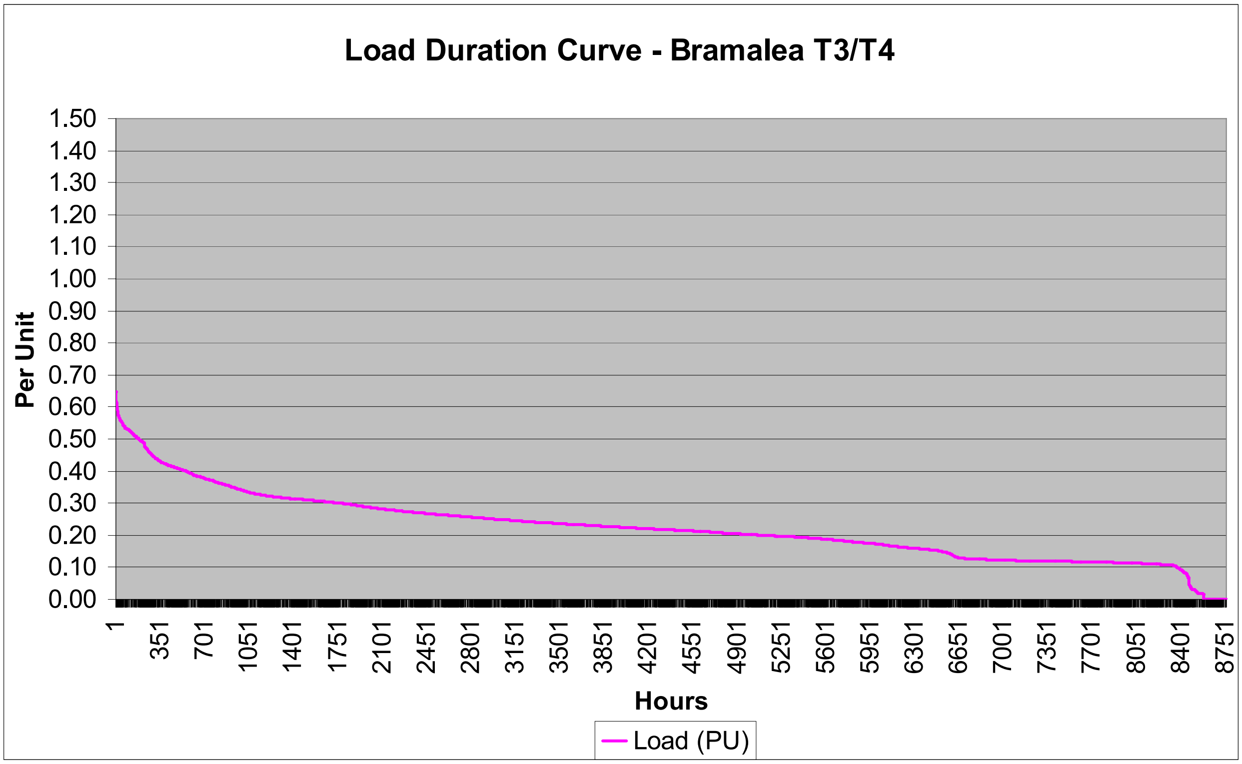
44 kV Transformer Stations

Bramalea TS






Load Duration Curve - Bramalea M25
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bramalea T3/T4
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1.40
1.30
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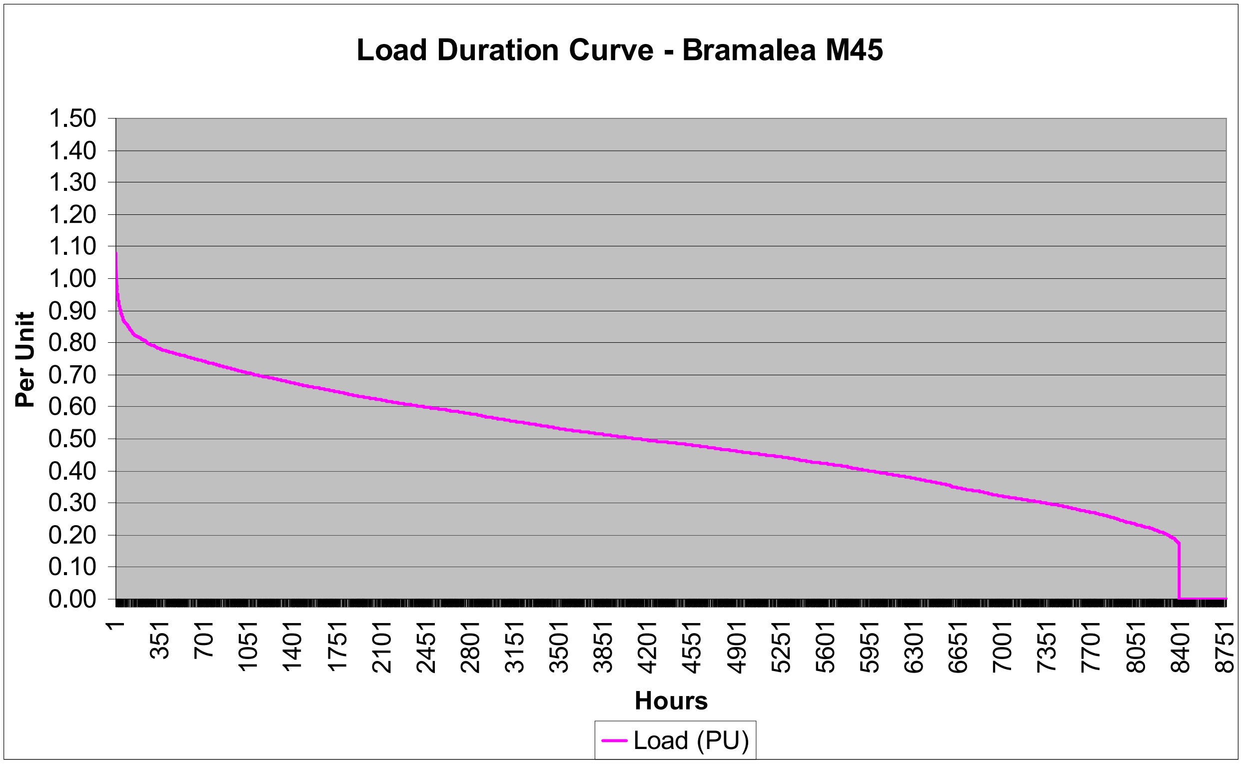
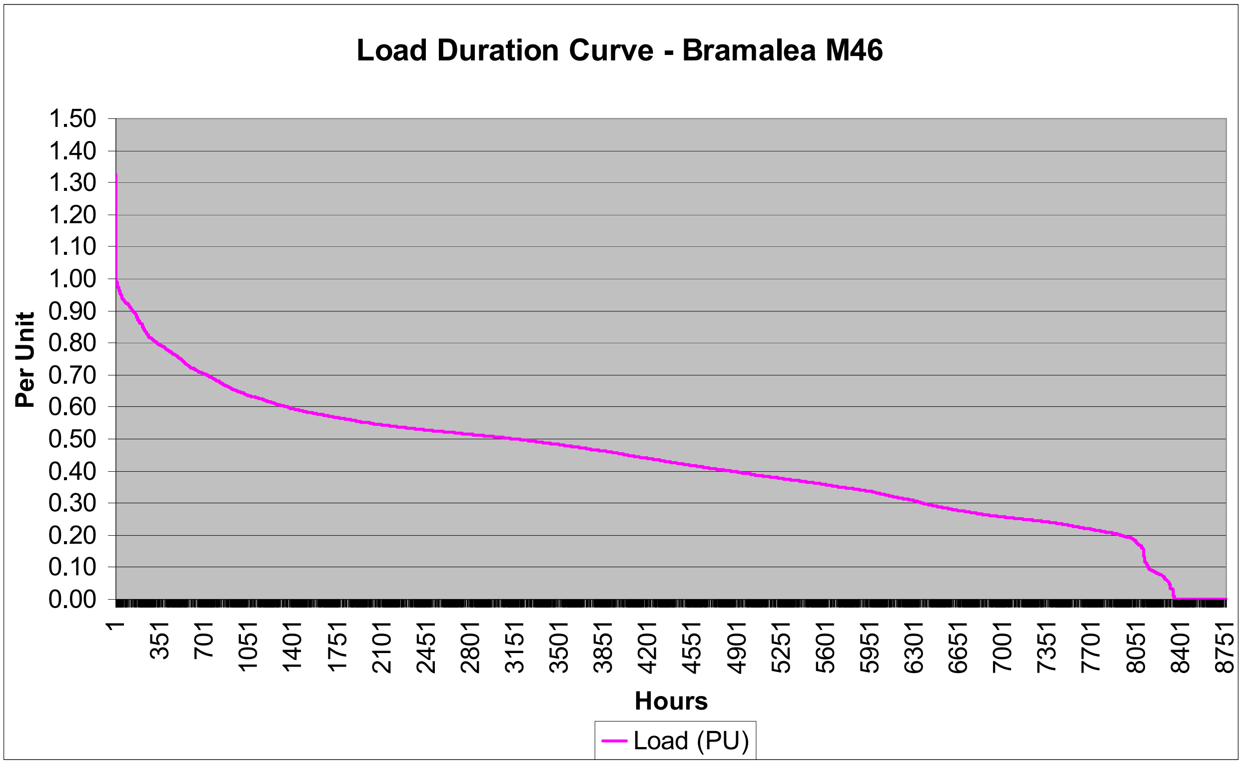
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Per Unit
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bramalea M45
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bramalea M46
Per Unit
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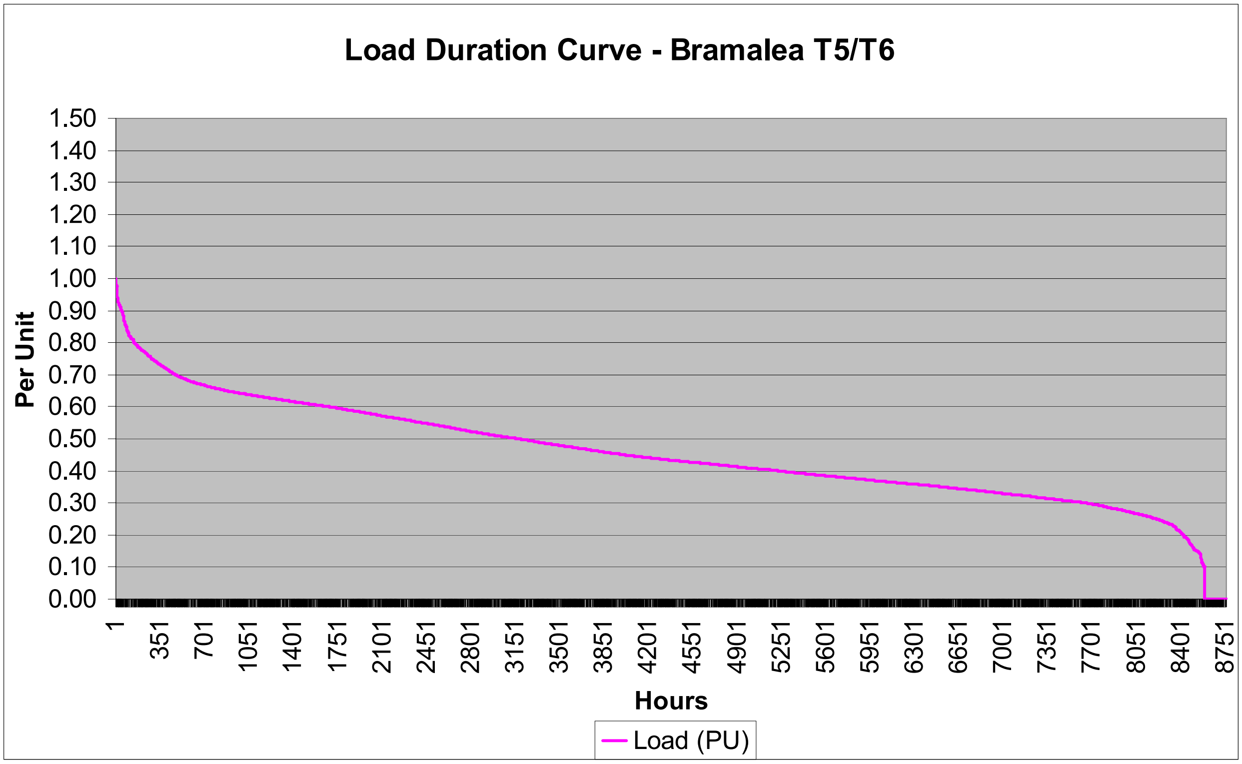
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
5251
5601
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Bramalea T5/T6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
4901
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6301
6651
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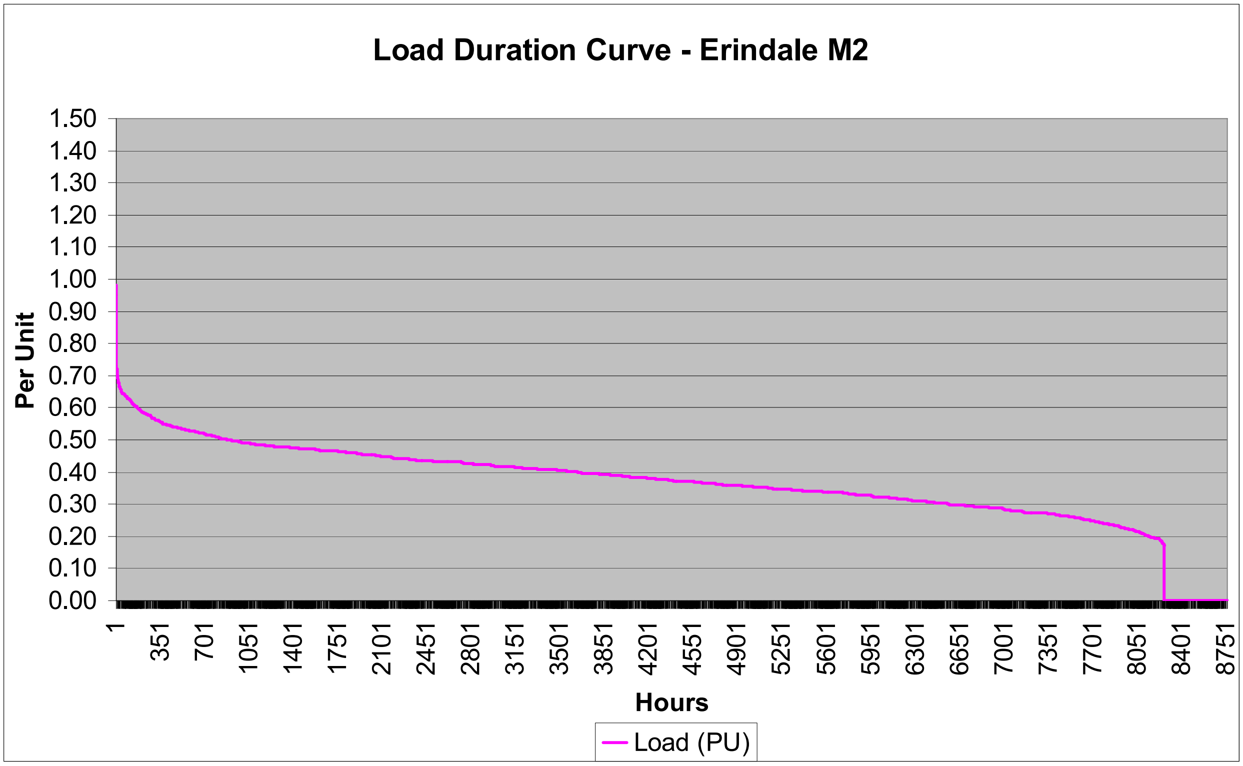
7351
7701
8051
8401
8751
Hours
Load (PU)

Erindale TS


Load Duration Curve - Erindale M2
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6301
6651
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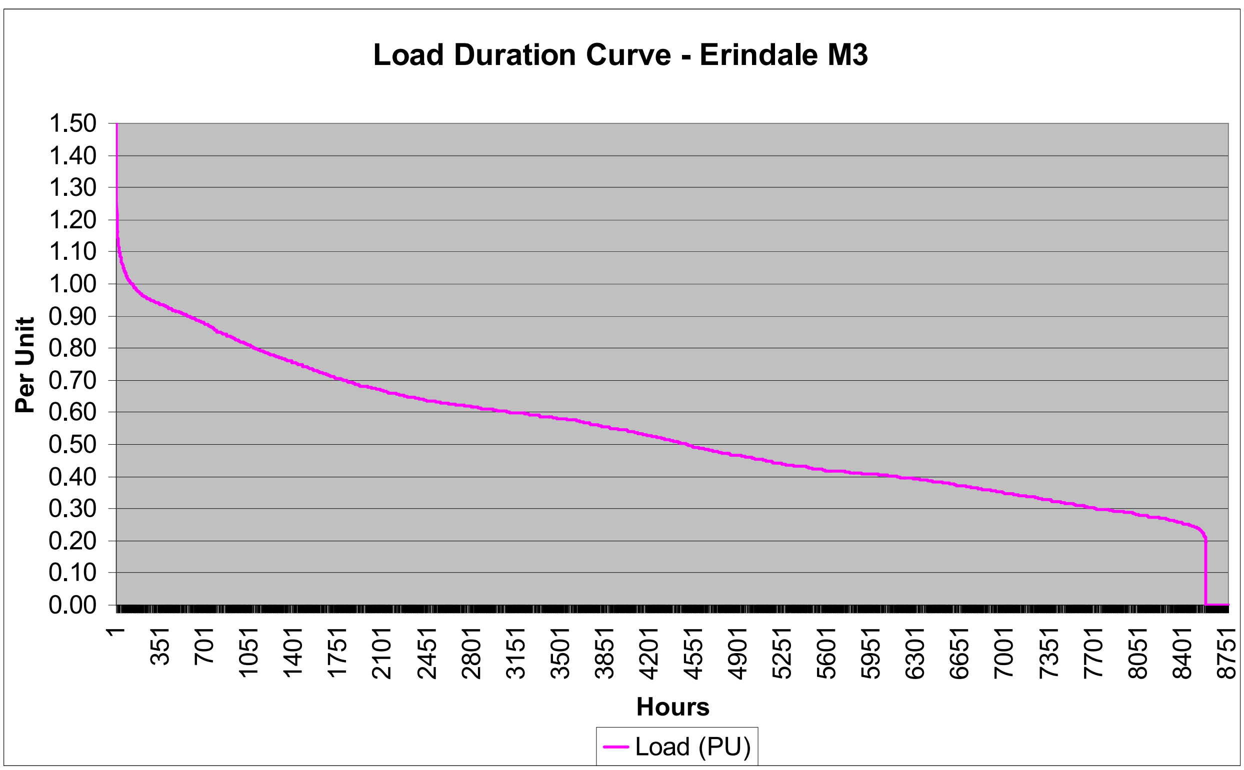
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M3
Per Unit
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1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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6301
6651
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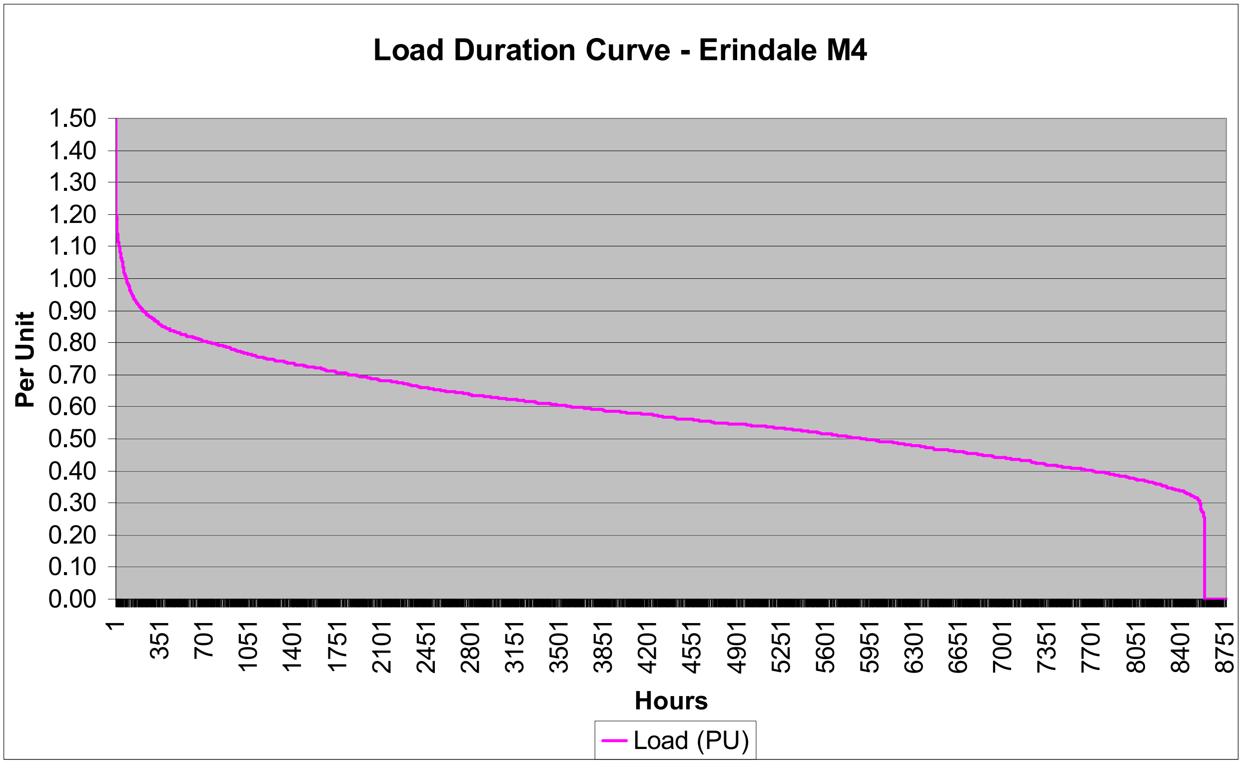
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M4
Per Unit
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1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6301
6651
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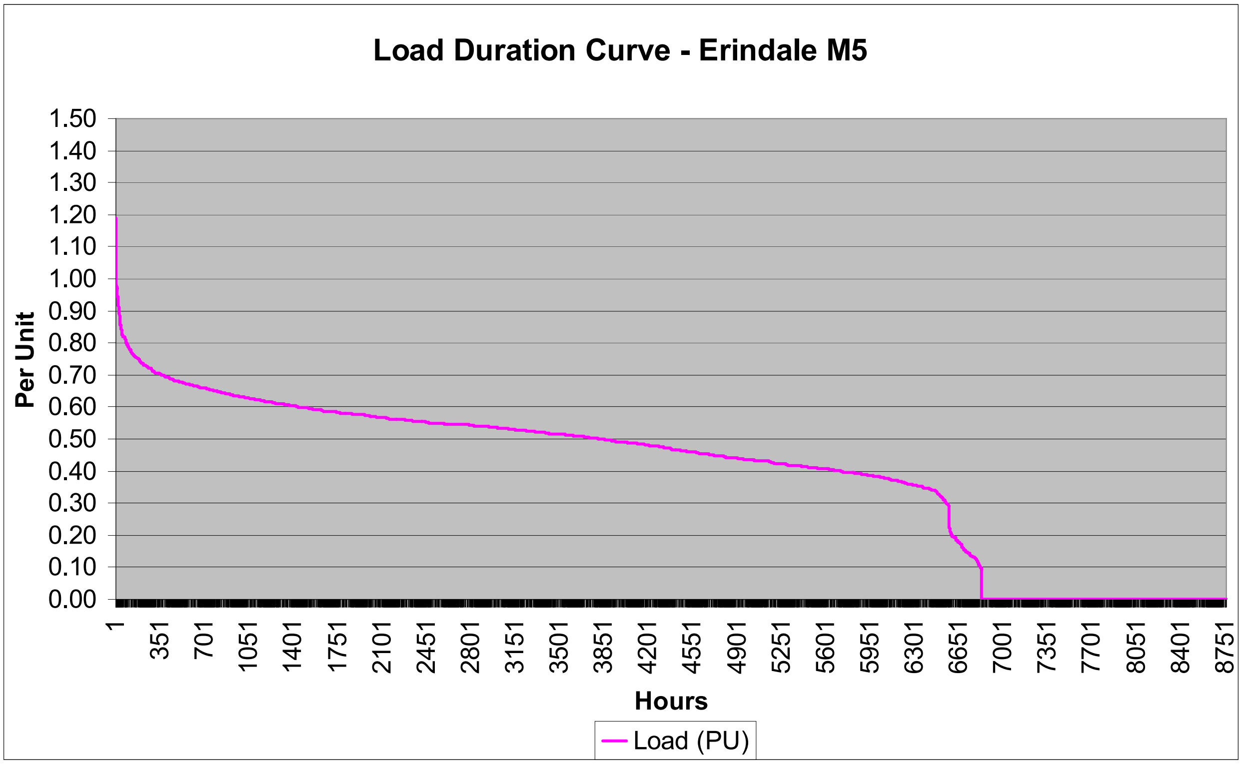
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M5
Per Unit
1.50
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
4551
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5251
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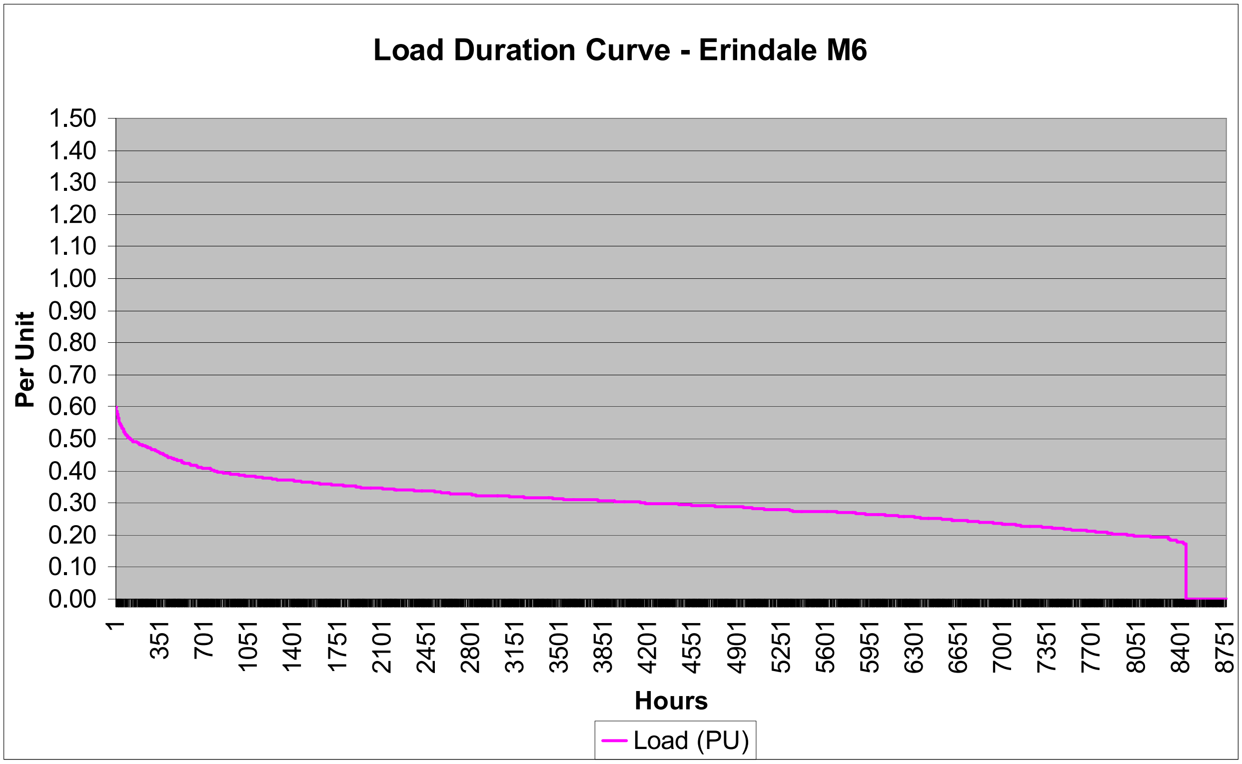
5951
6301
6651
7001
7351
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M6
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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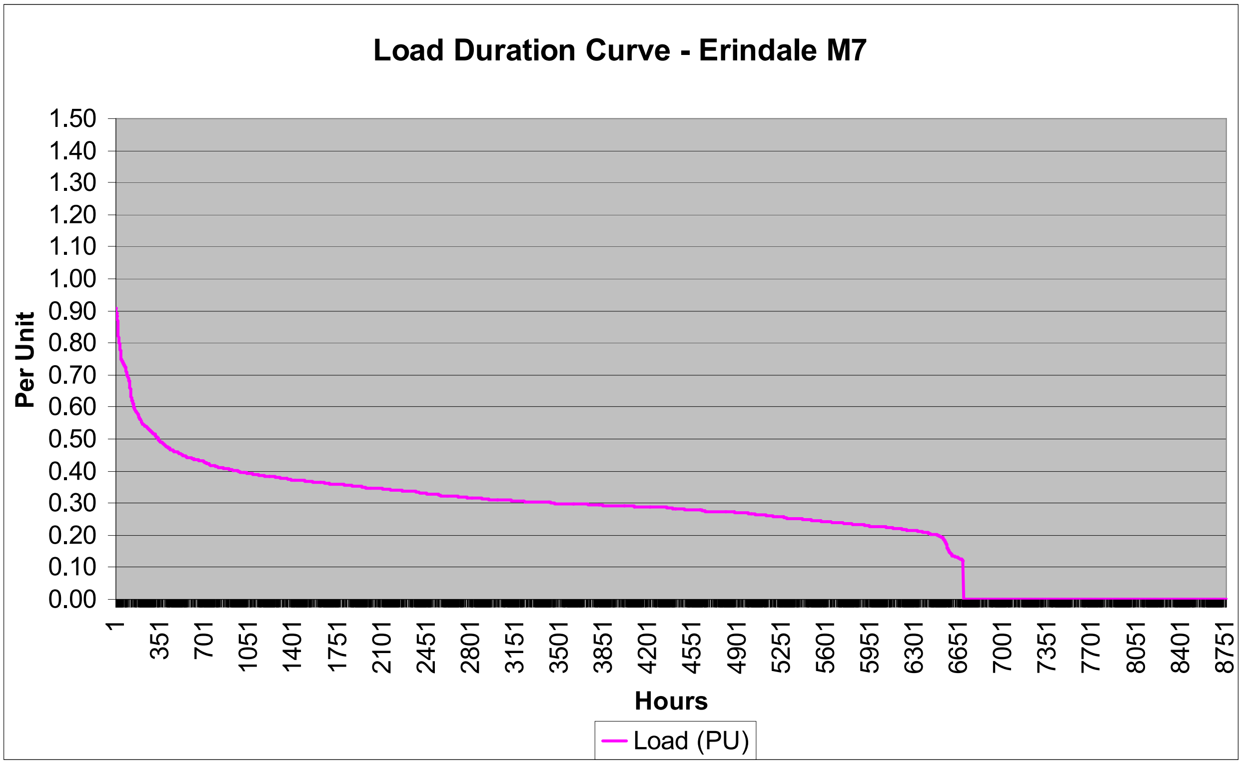
7701
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M7
Per Unit
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1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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6651
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7701
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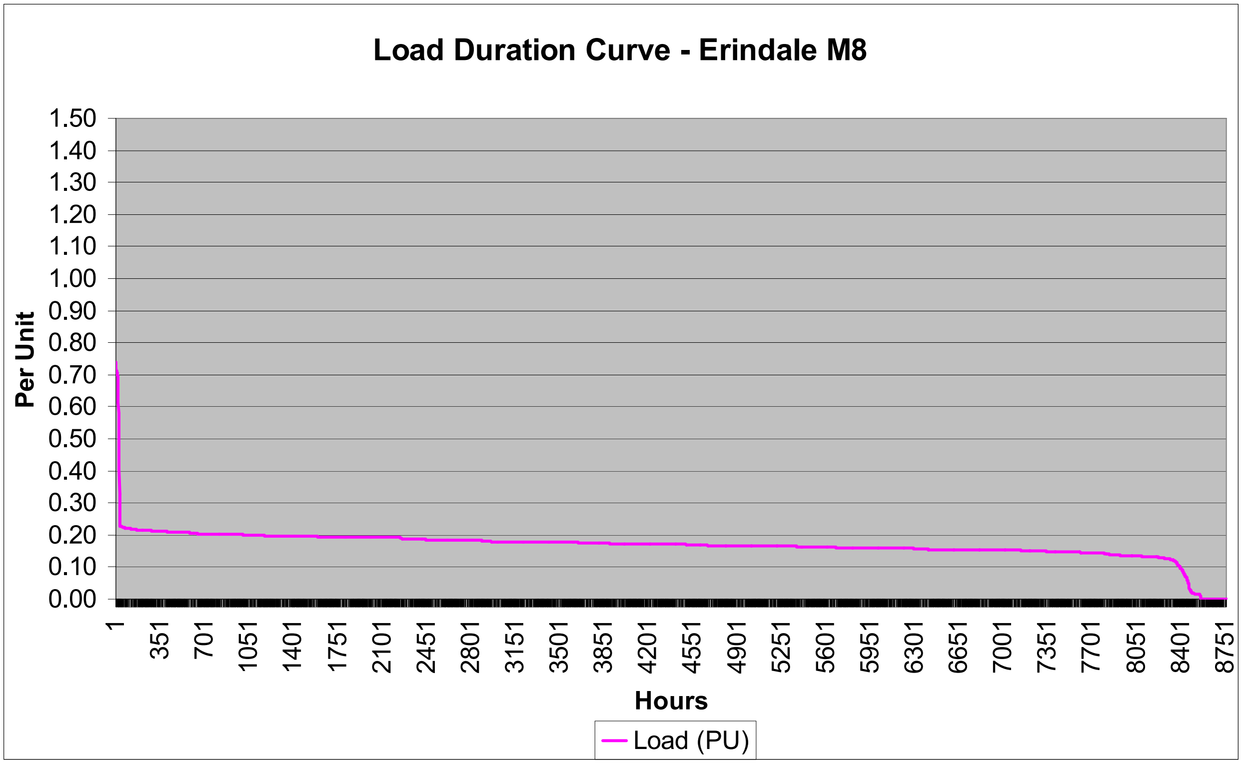
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M8
Per Unit
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1.20
1.10
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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5251
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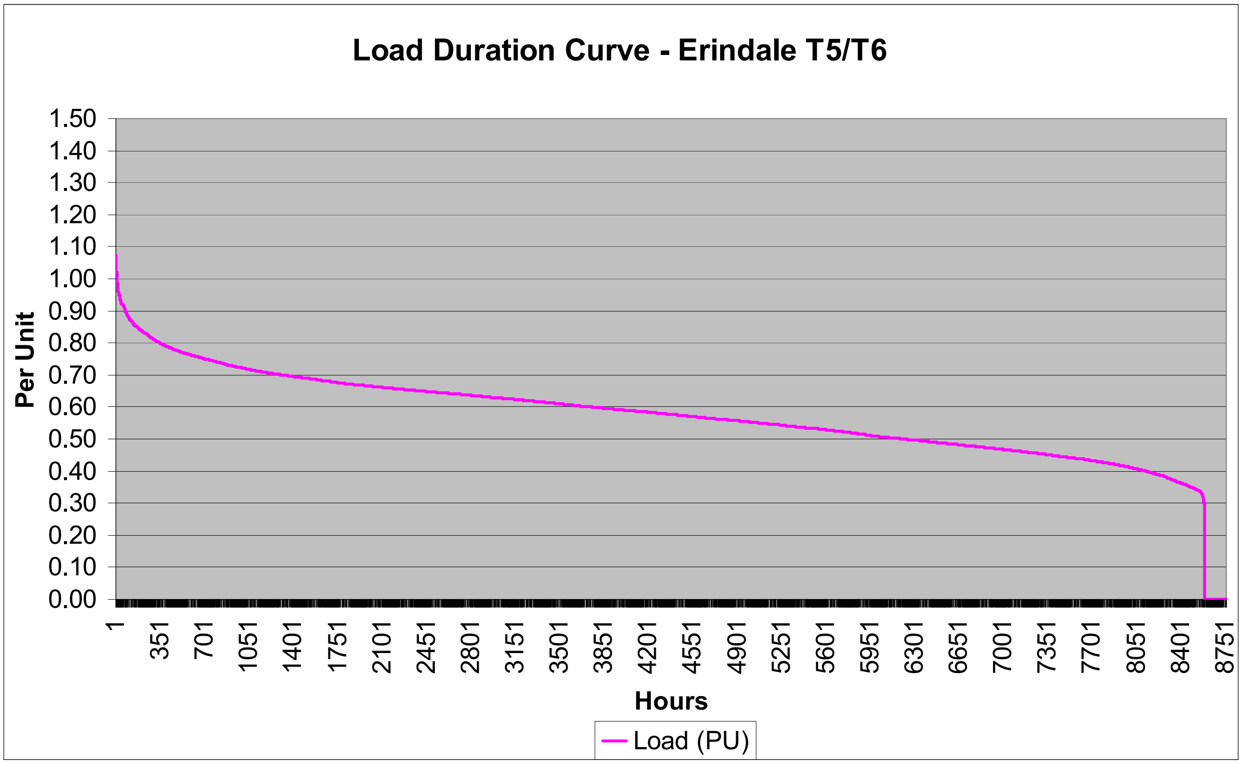
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale T5/T6
Per Unit
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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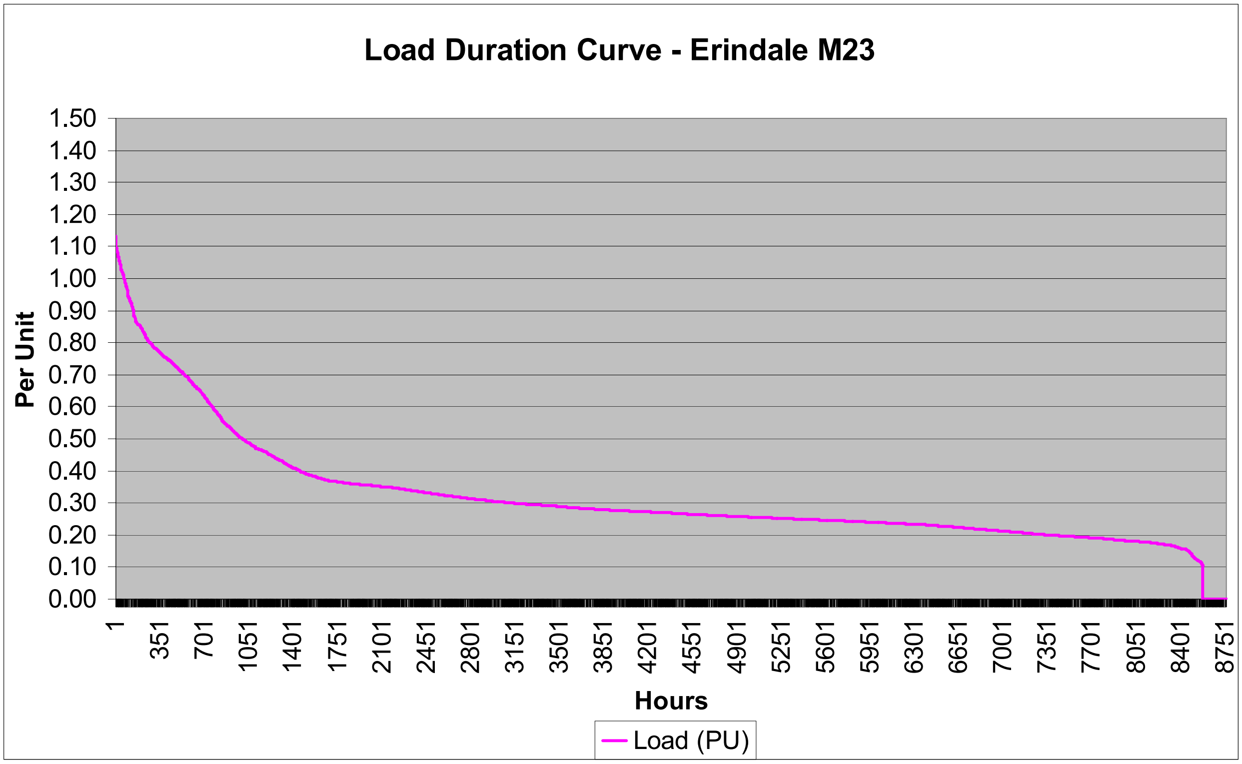
7701
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Erindale M23
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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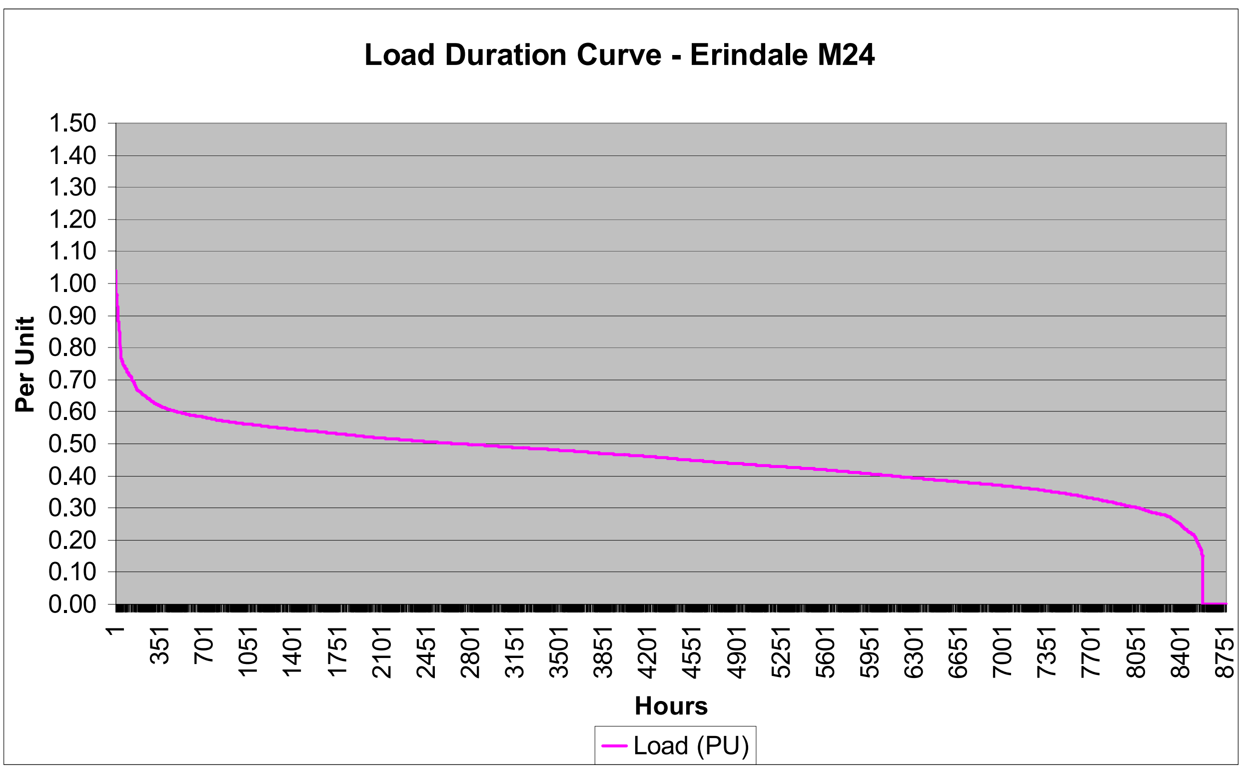
8051
8401
8751
Hours
Load (PU)



Load Duration Curve - Erindale M24
Per Unit
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0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
2801
3151
3501
3851
4201
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4901
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5601
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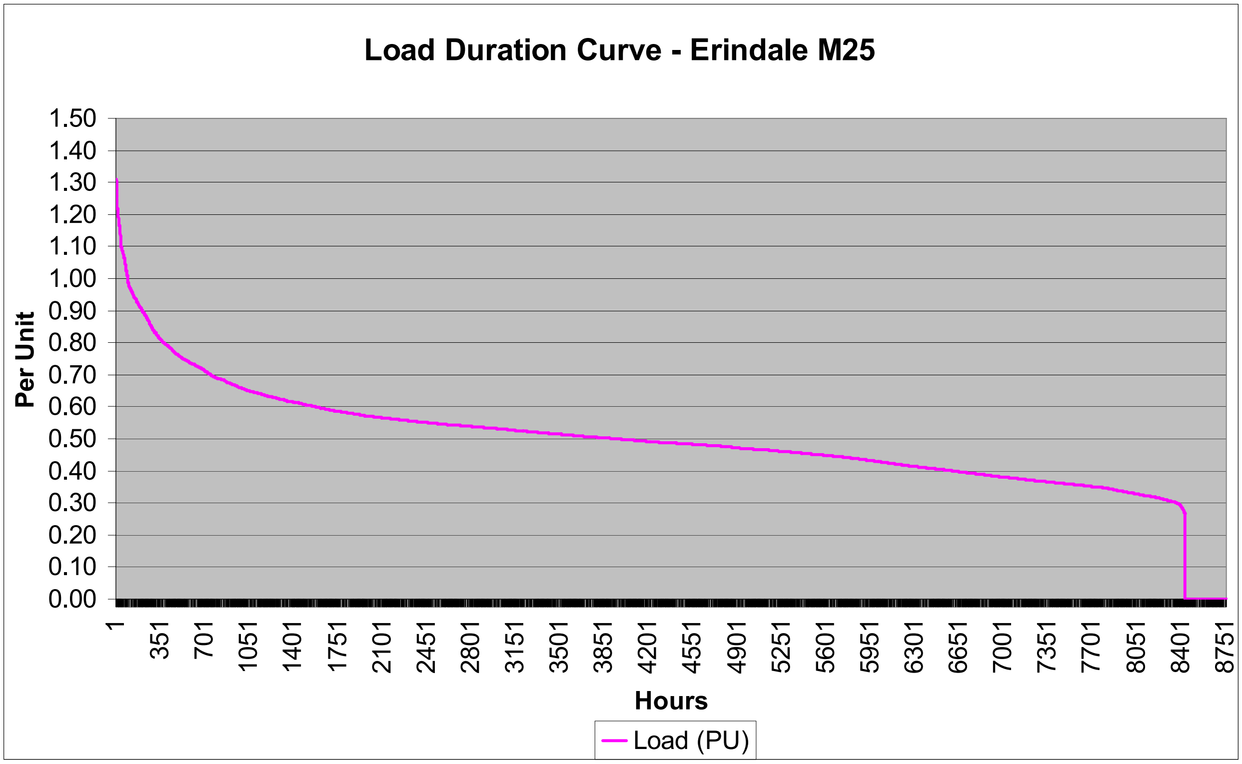
8051
8401
8751
Hours
Load (PU)


Load Duration Curve - Erindale M25
Per Unit
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
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2451
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4201
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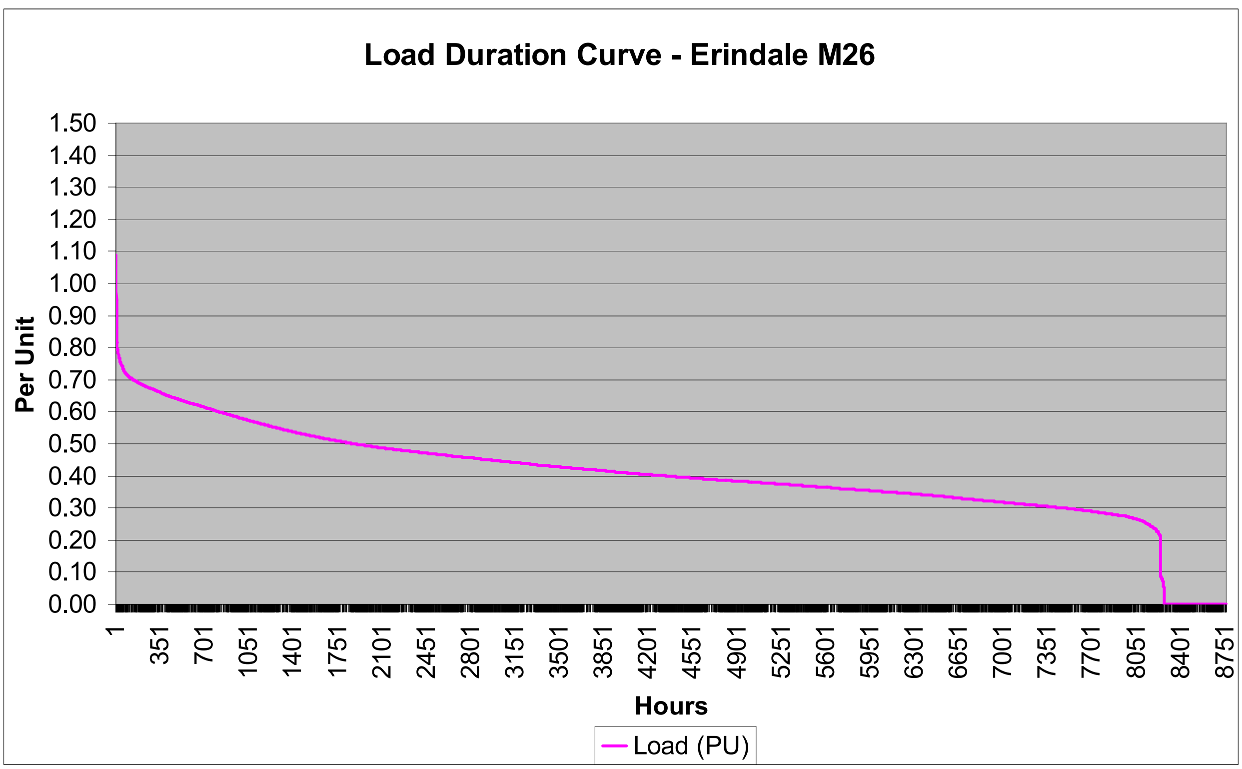
8751
Hours
Load (PU)


Load Duration Curve - Erindale M26
Per Unit
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0.90
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0.60
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0.30
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0.00
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4201
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8401
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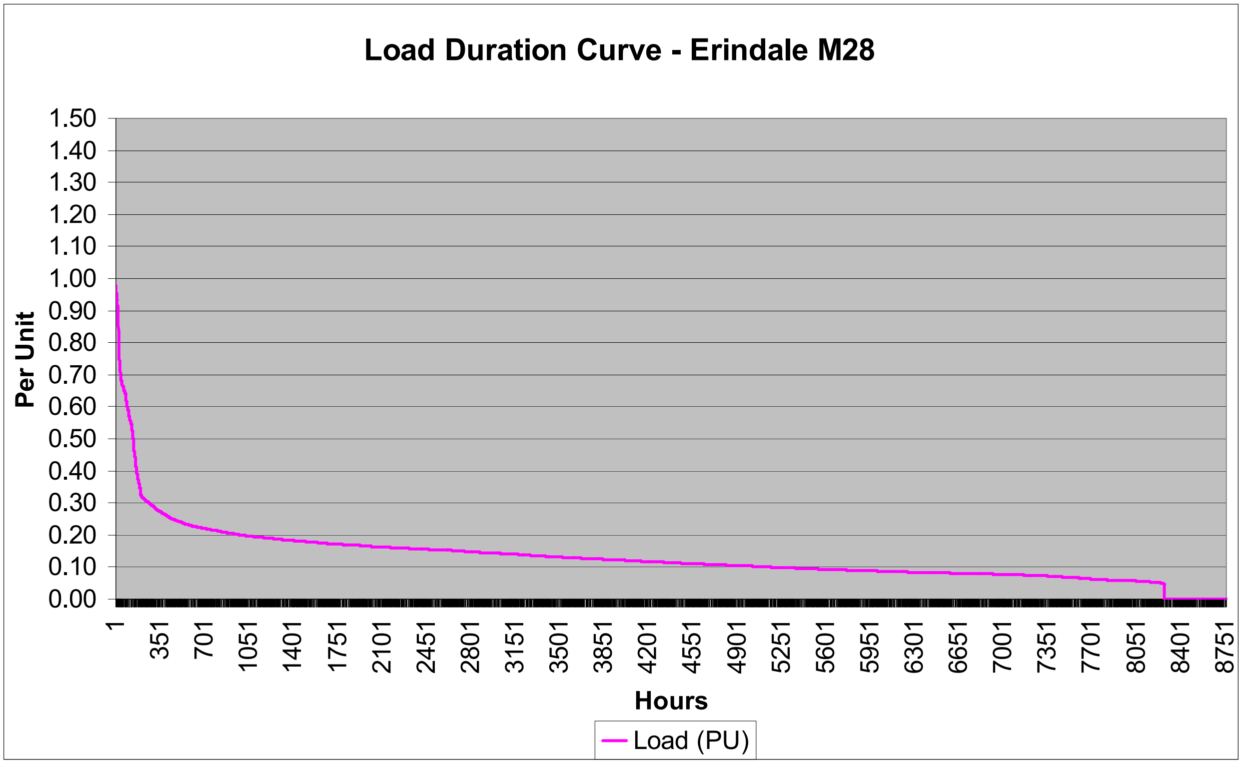
Hours
Load (PU)



Load Duration Curve - Erindale M28
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0.60
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0.30
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0.10
0.00
1
351
701
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8401
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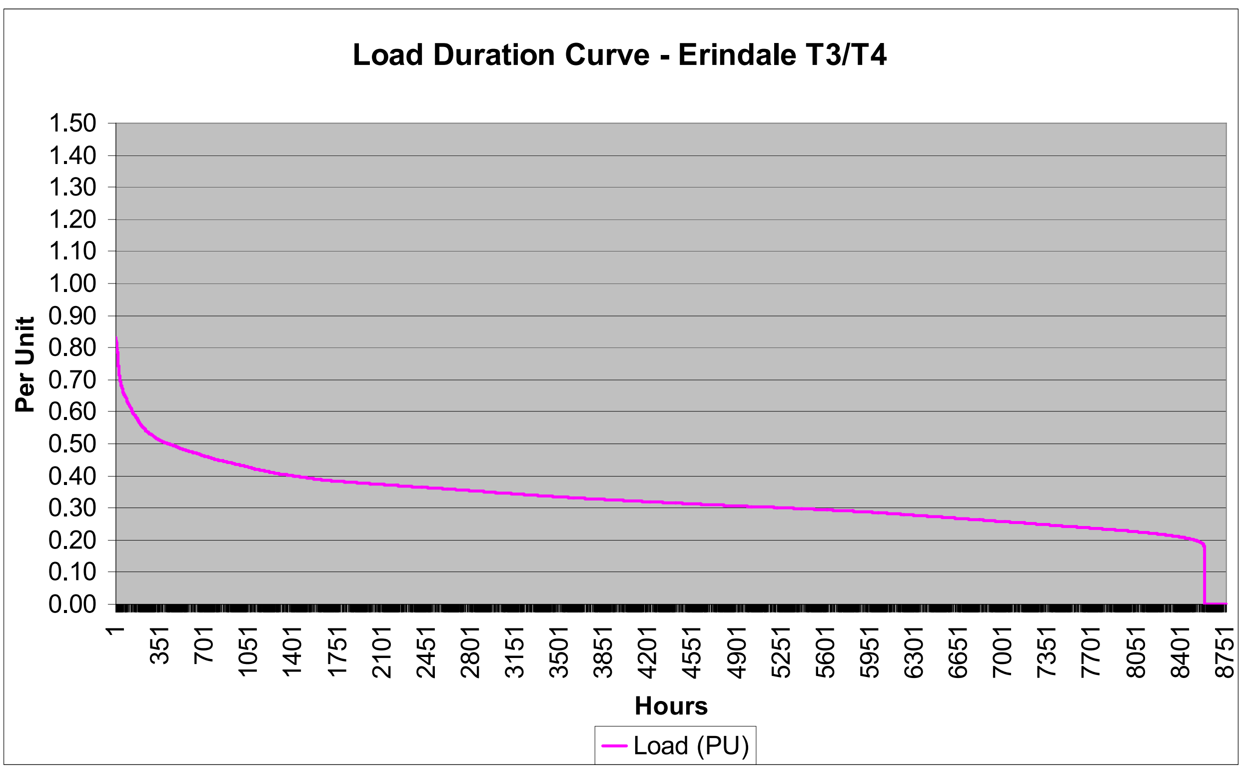
Hours
Load (PU)



Load Duration Curve - Erindale T3/T4
Per Unit
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1.10
1.00
0.90
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0.60
0.50
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0.10
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4551
4901
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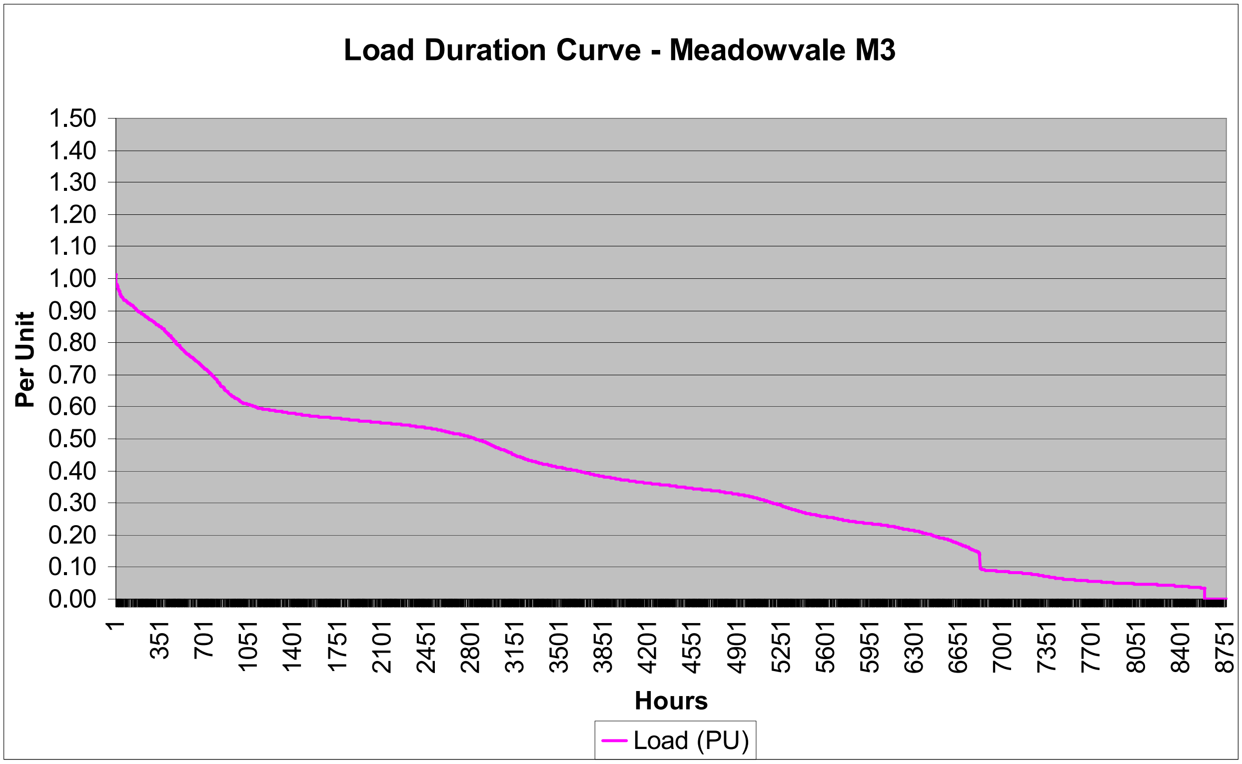
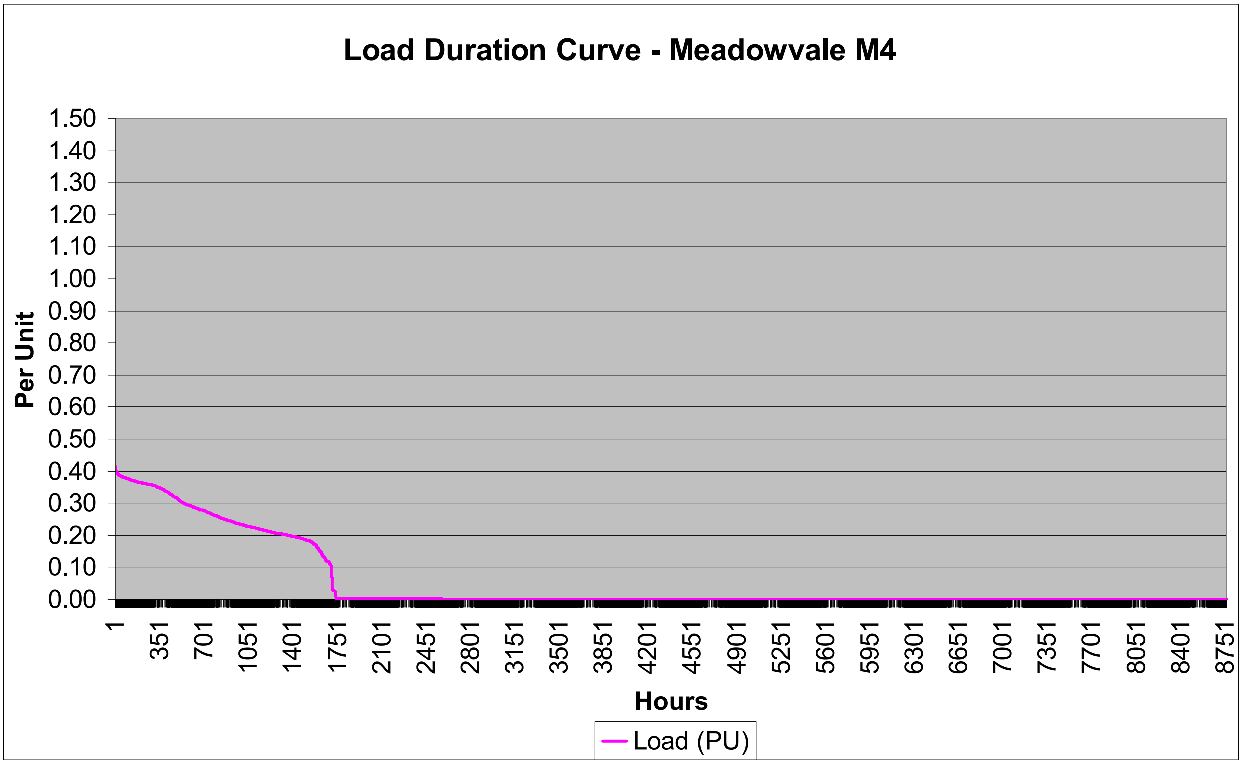
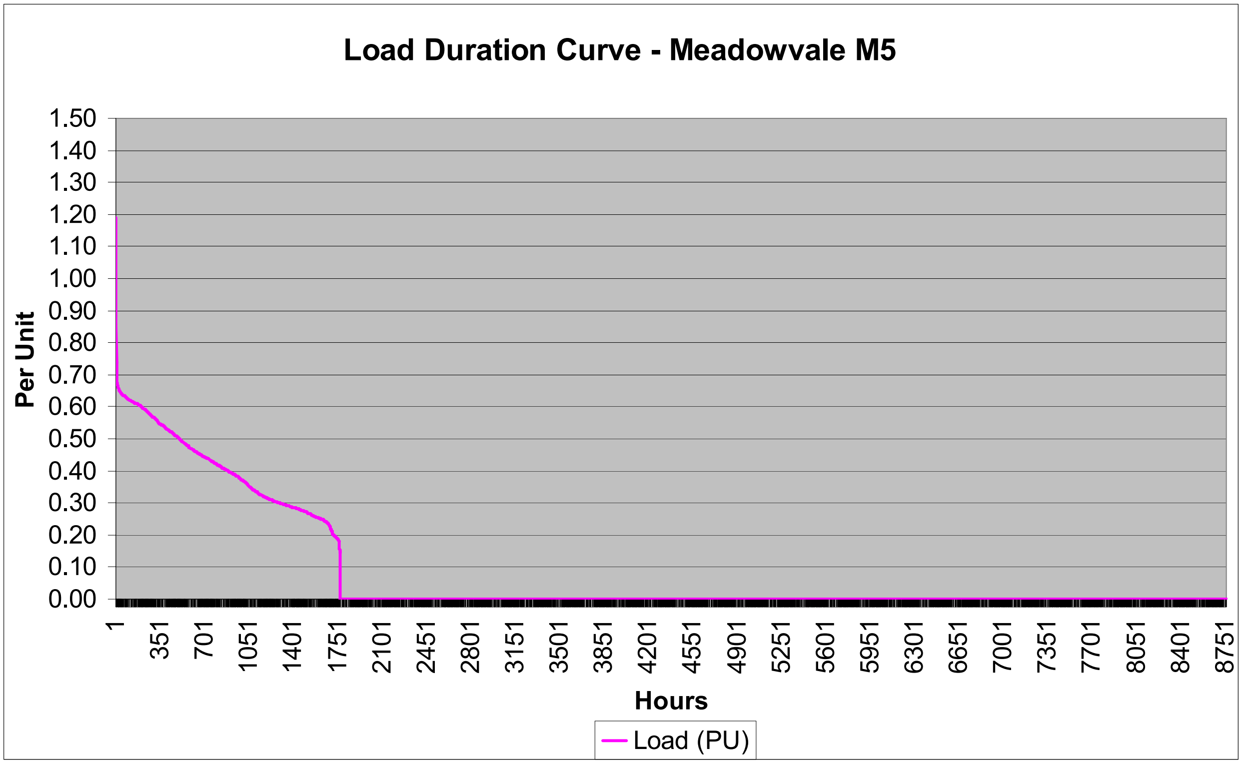
8051
8401
8751
Hours
Load (PU)

Meadowvale TS






Load Duration Curve - Meadowvale M5
Per Unit
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0.90
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
1
351
701
1051
1401
1751
2101
2451
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4201
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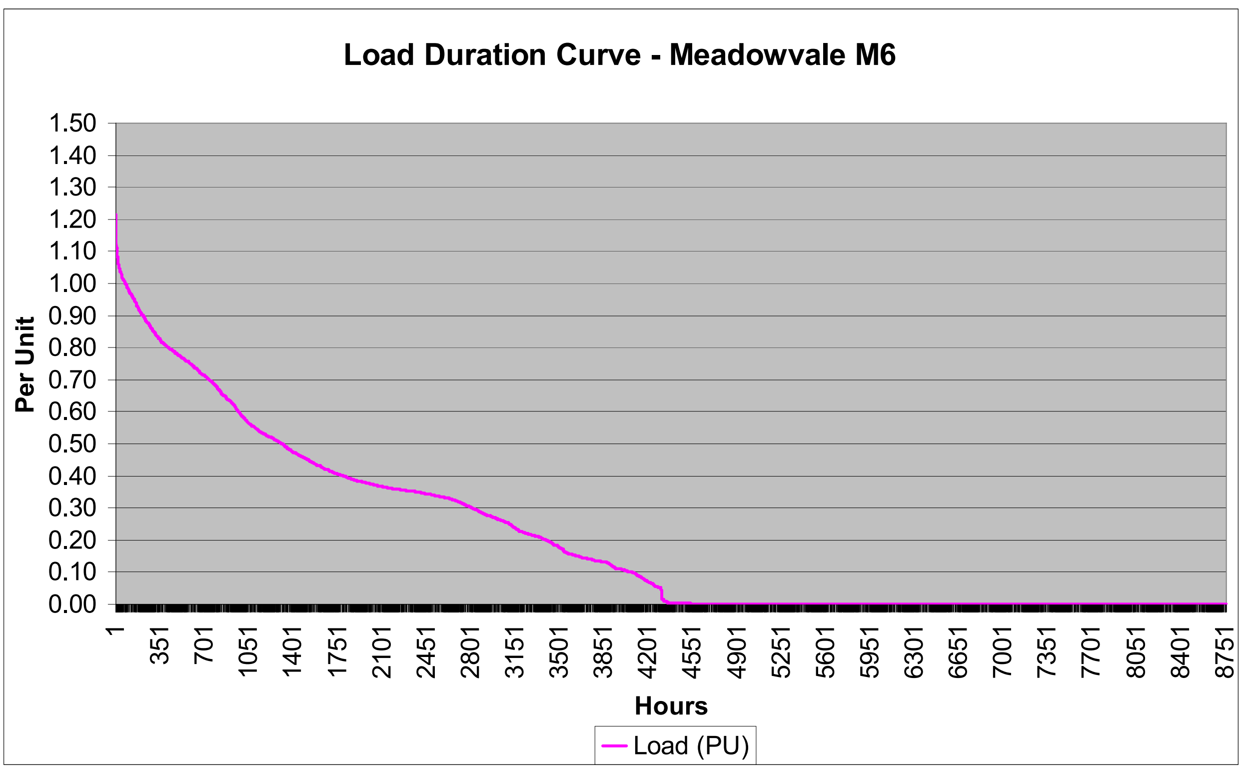
Load Duration Curve - Meadowvale M6
Per Unit
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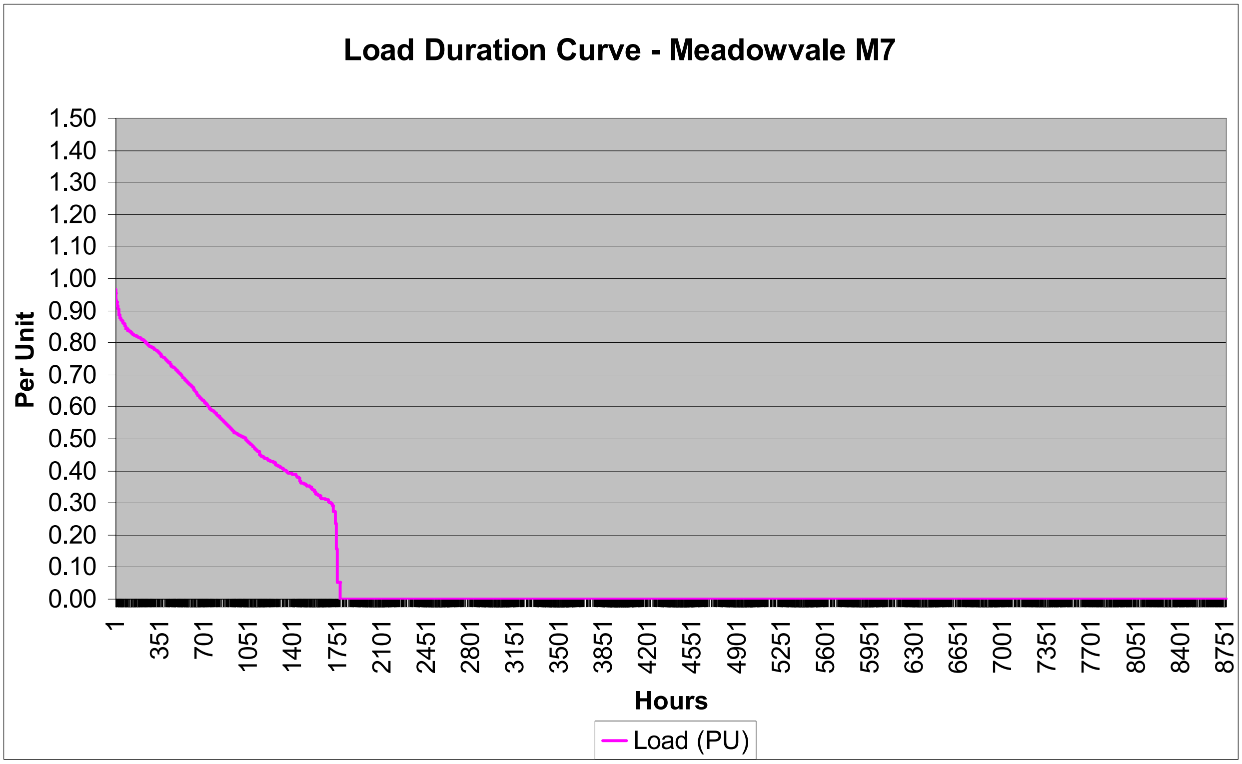
Load Duration Curve - Meadowvale M7
Per Unit
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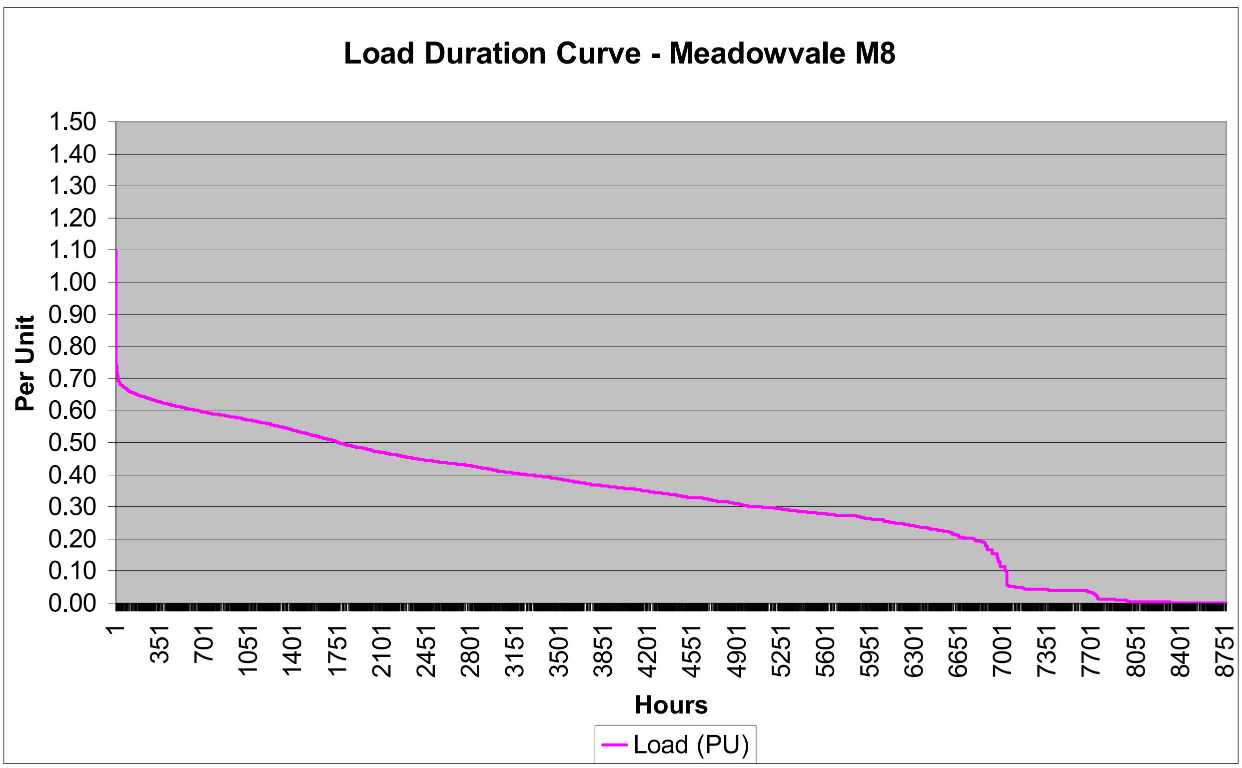
Hours
Load (PU)


Load Duration Curve - Meadowvale M8
Per Unit
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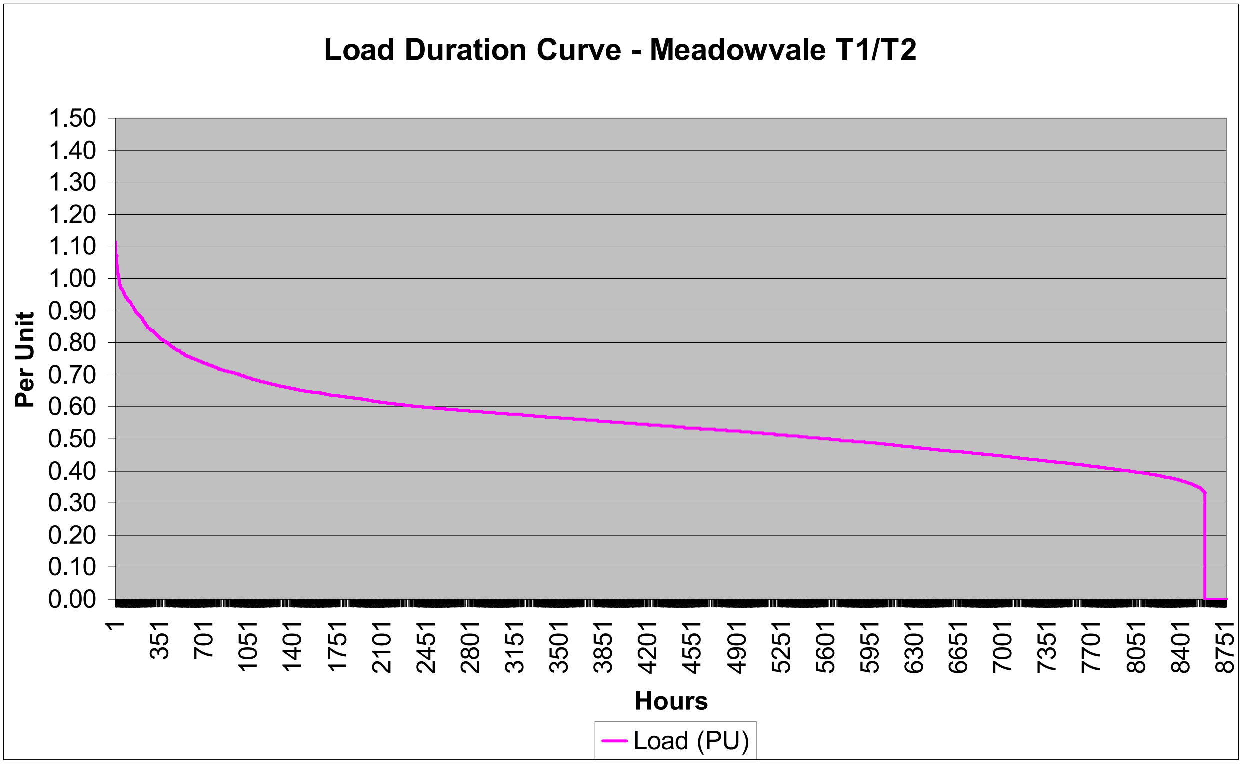
Load Duration Curve - Meadowvale T1/T2
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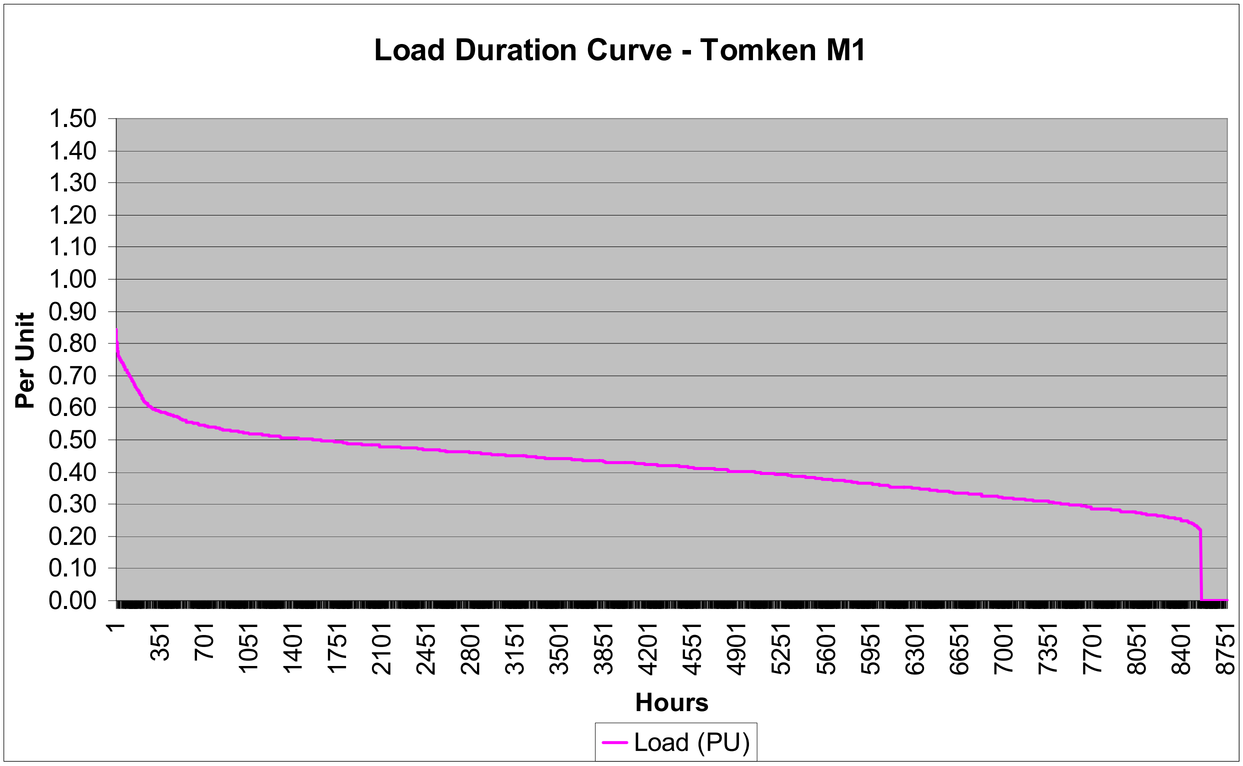
Hours
Load (PU)

Tomken TS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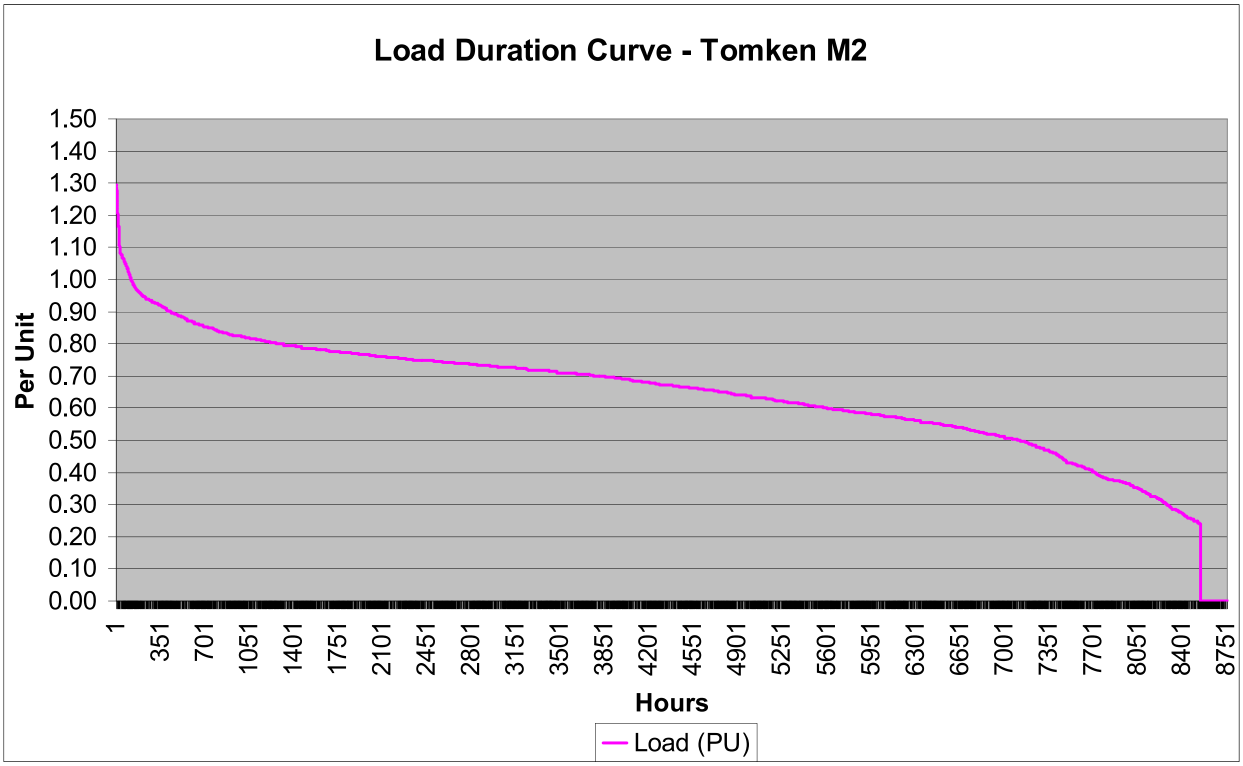
Load (PU)


Load Duration Curve - Tomken M2
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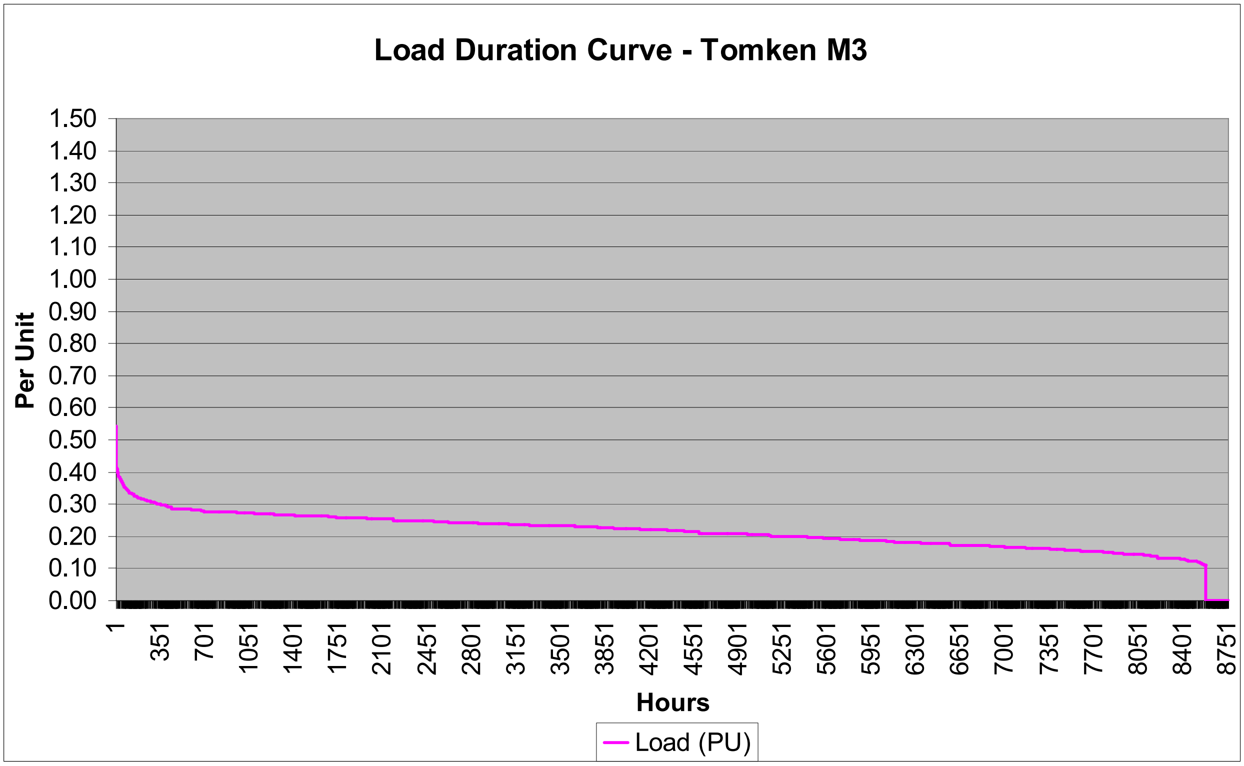
Hours
Load (PU)


Load Duration Curve - Tomken M3
Per Unit
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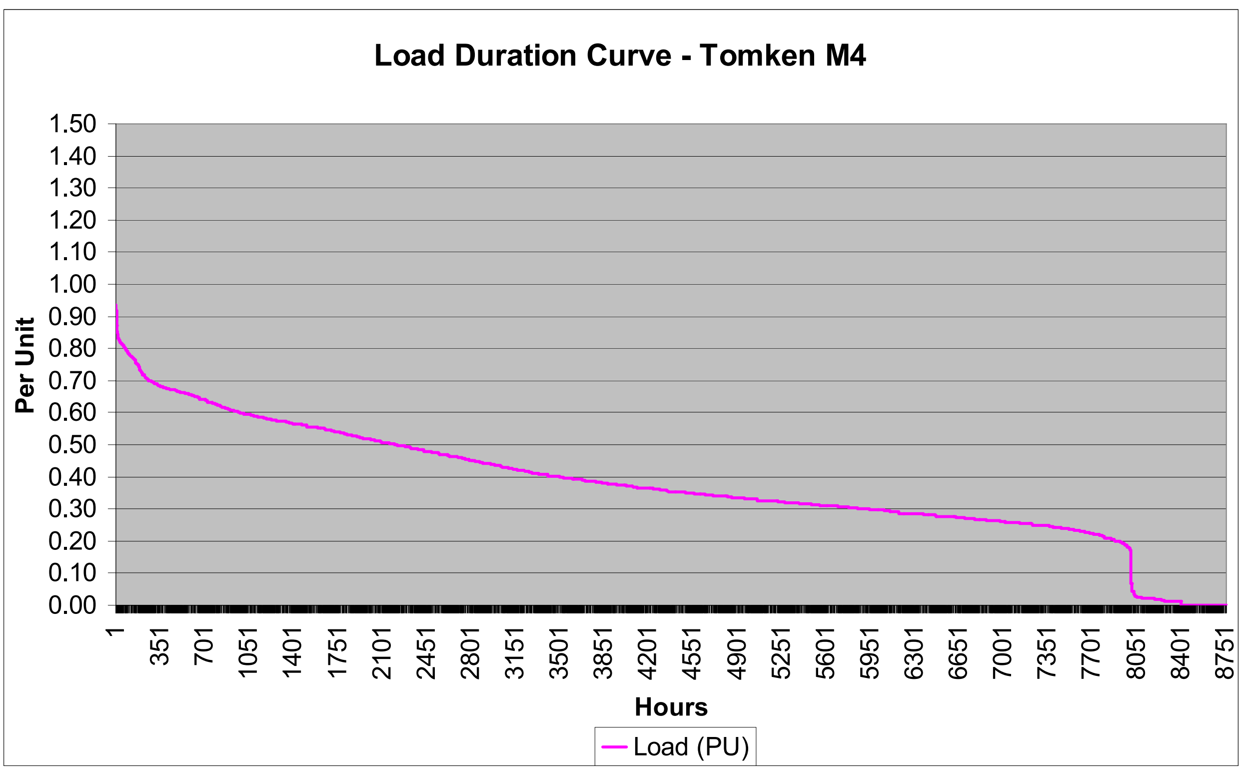
Load (PU)


Load Duration Curve - Tomken M4
Per Unit
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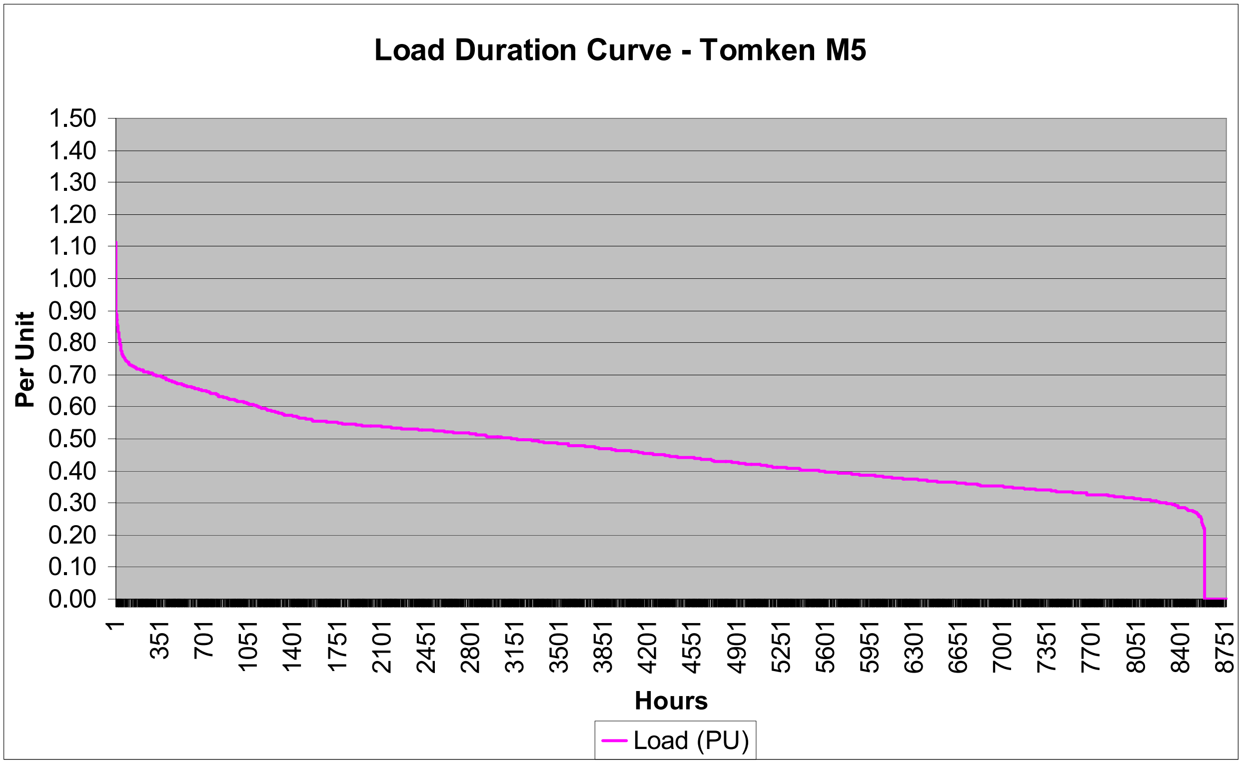
Load (PU)


Load Duration Curve - Tomken M5
Per Unit
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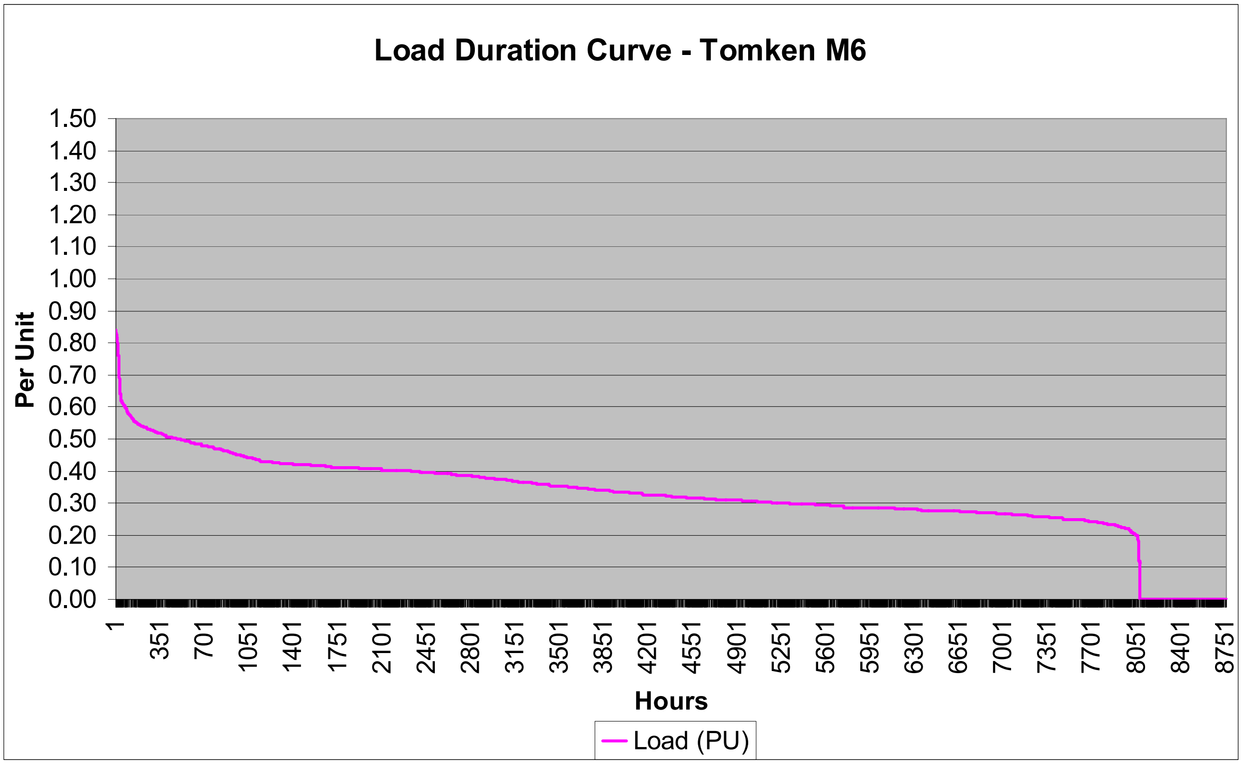
Load (PU)


Load Duration Curve - Tomken M6
Per Unit
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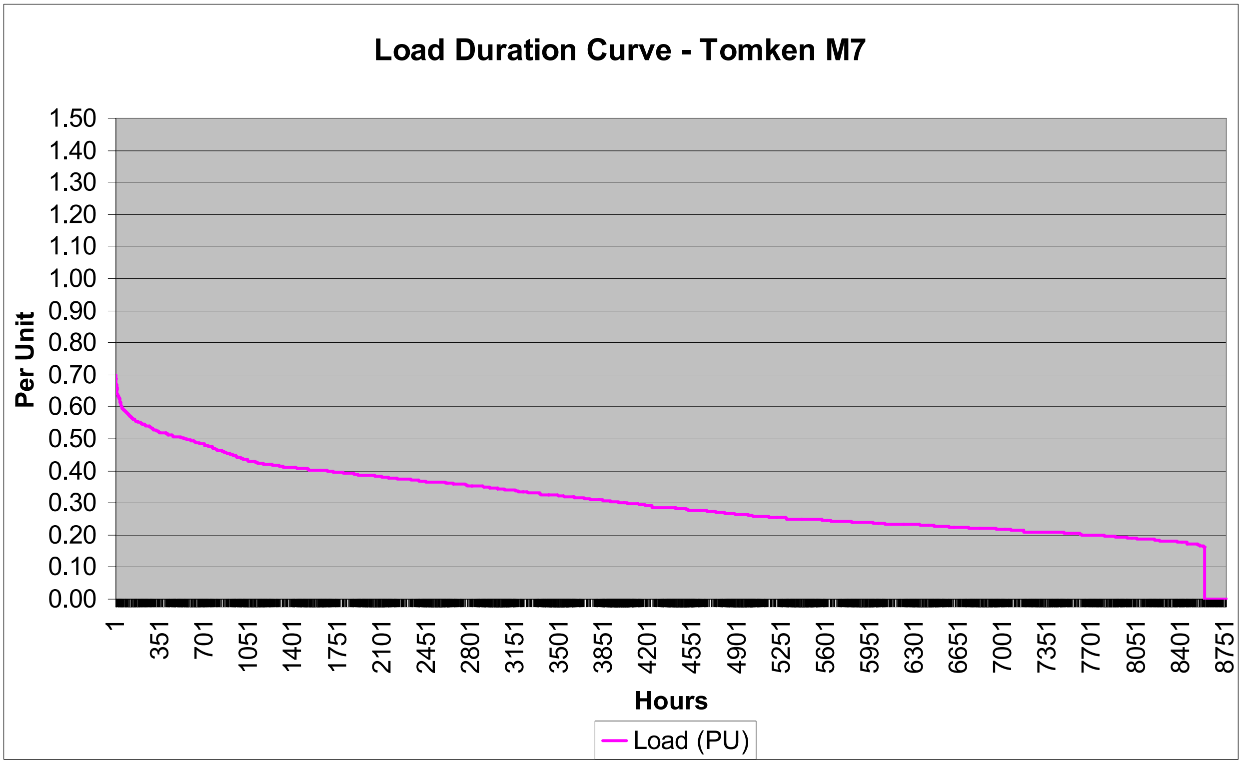
Load (PU)


Load Duration Curve - Tomken M7
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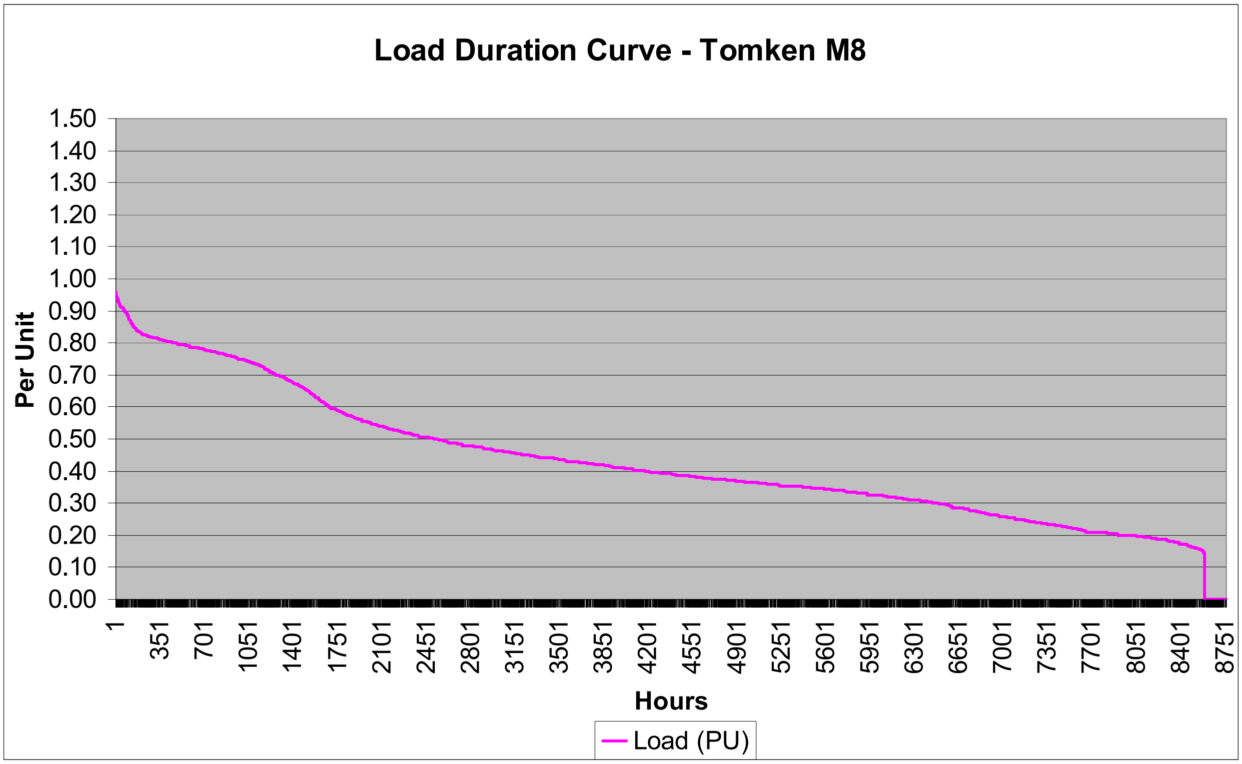
Load Duration Curve - Tomken M8
Per Unit
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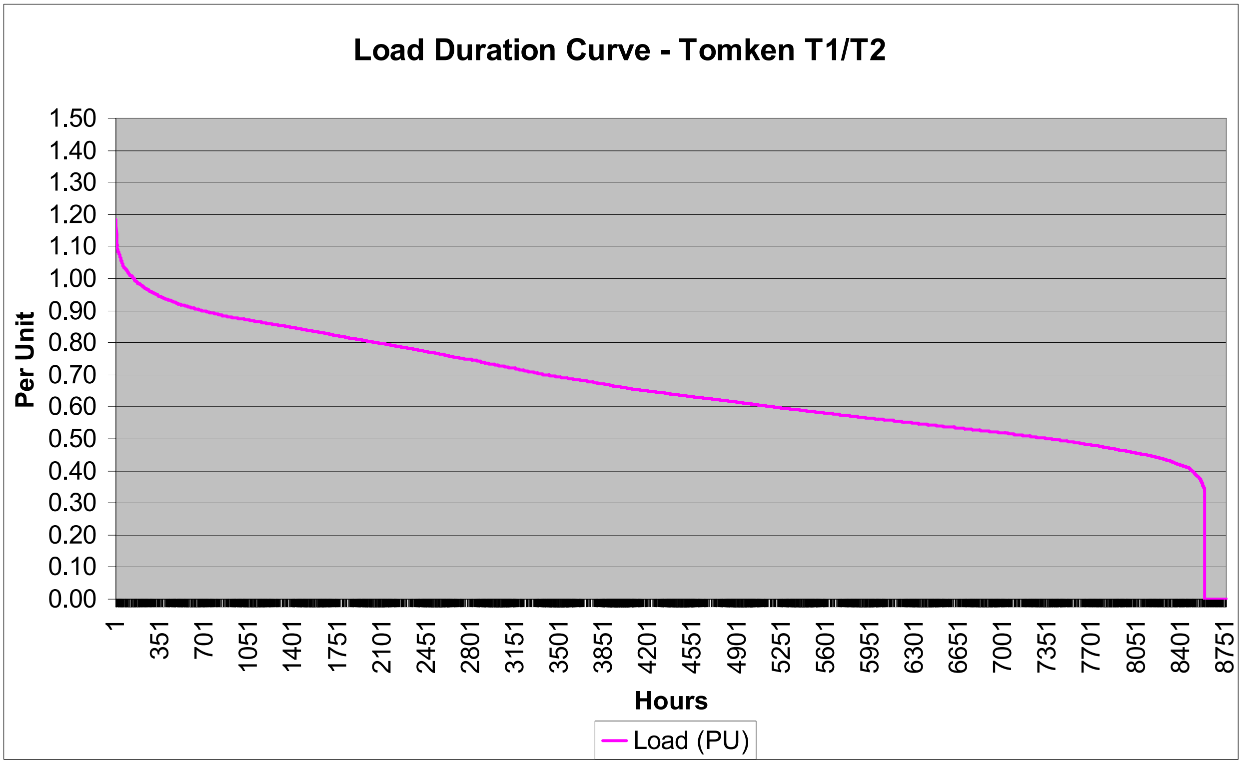
Hours
Load (PU)


Load Duration Curve - Tomken T1/T2
Per Unit
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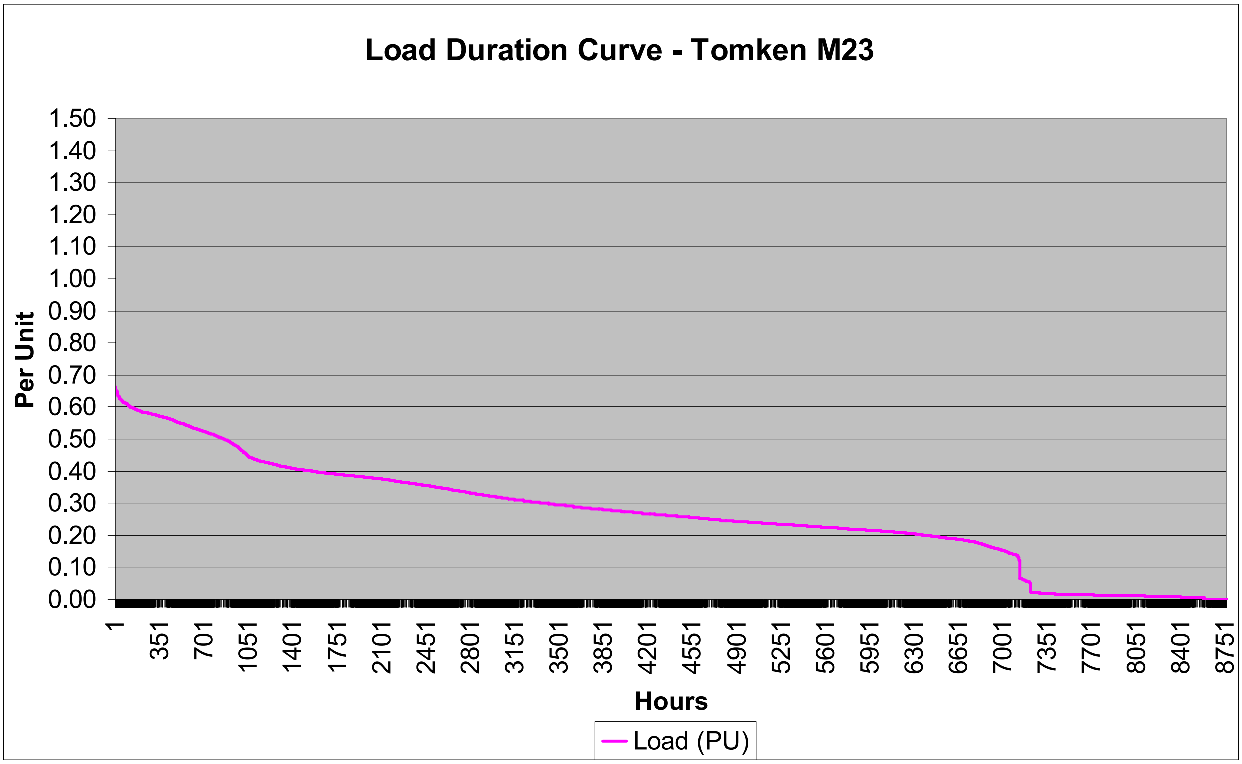
Hours
Load (PU)


Load Duration Curve - Tomken M23
Per Unit
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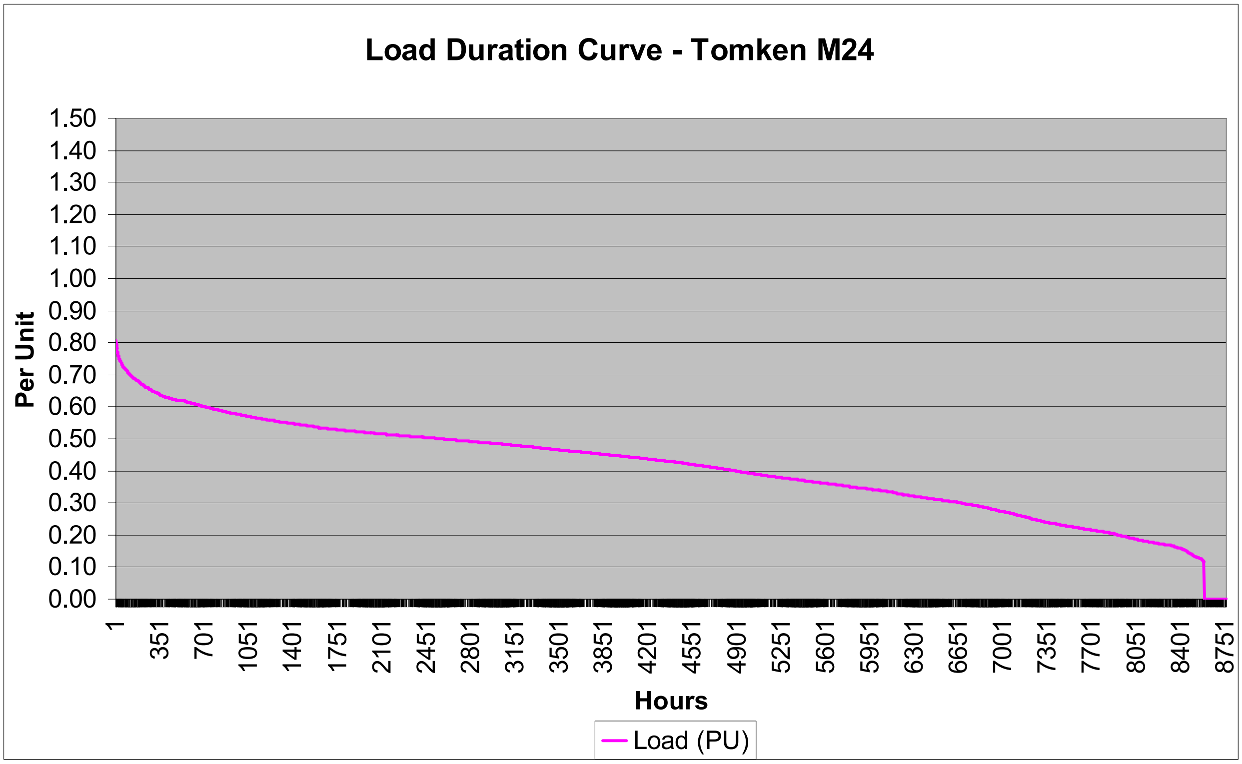
Hours
Load (PU)


Load Duration Curve - Tomken M24
Per Unit
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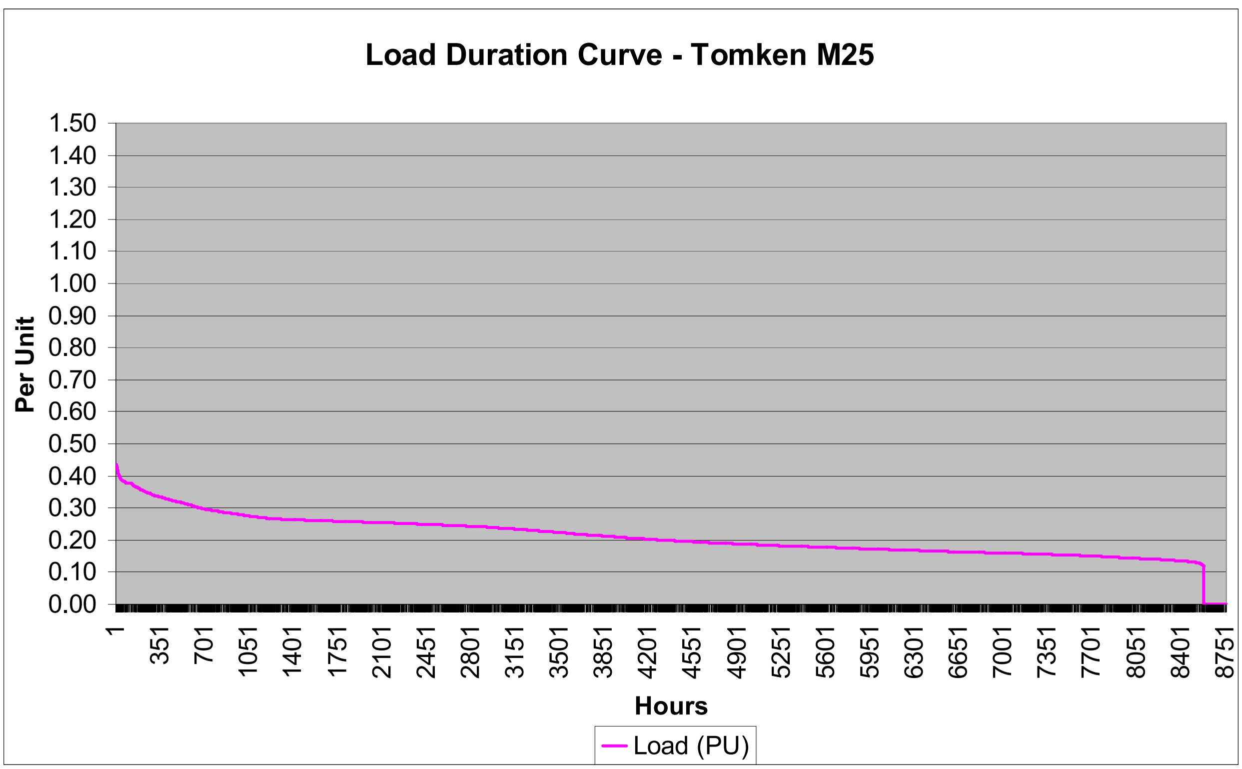
Hours
Load (PU)


Load Duration Curve - Tomken M25
Per Unit
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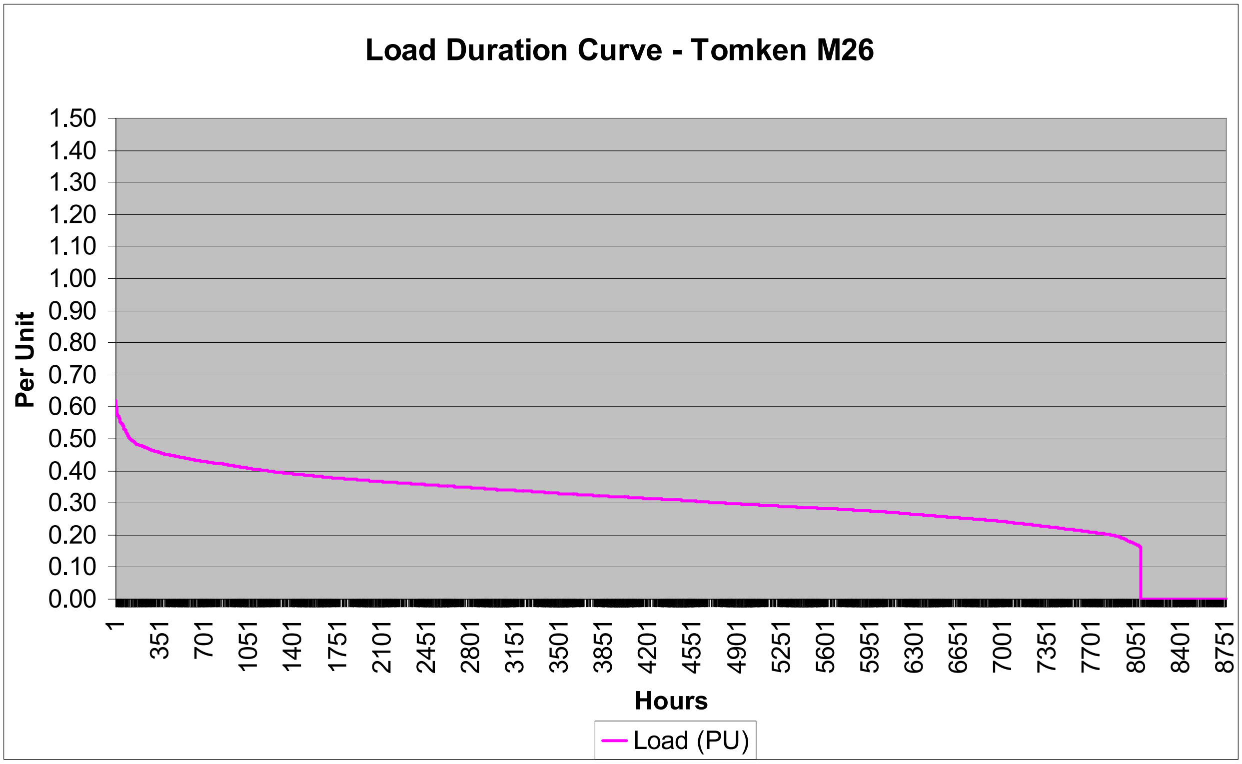
Hours
Load (PU)



Load Duration Curve - Tomken M26
Per Unit
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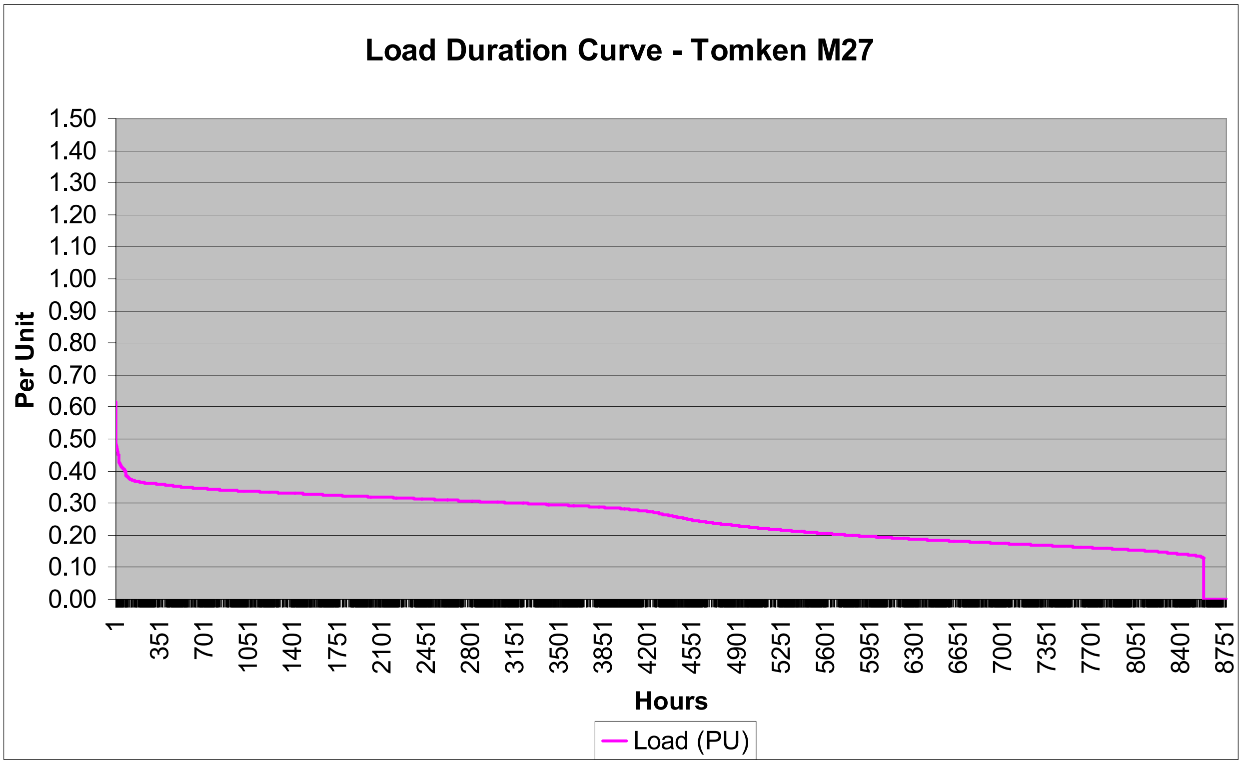
Hours
Load (PU)



Load Duration Curve - Tomken M27
Per Unit
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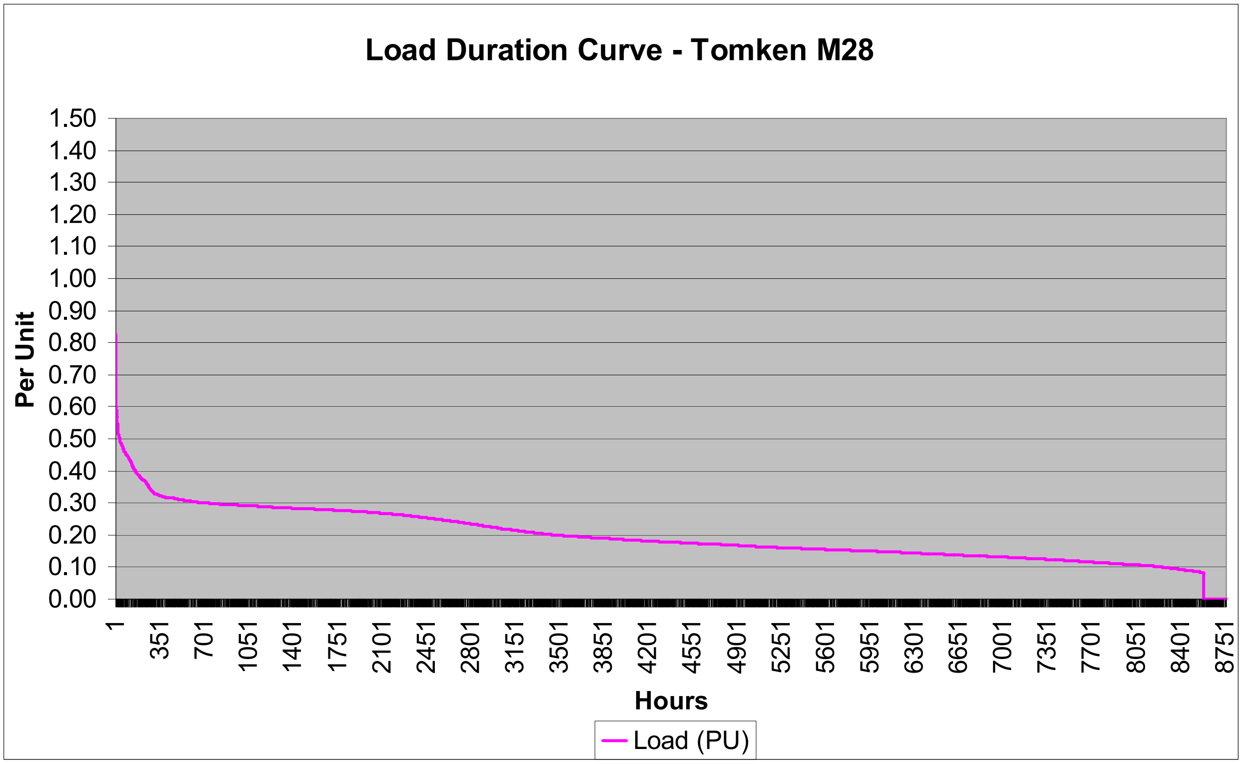
Hours
Load (PU)


Load Duration Curve - Tomken M28
Per Unit
1.50
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1.30
1.20
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1.00
0.90
0.80
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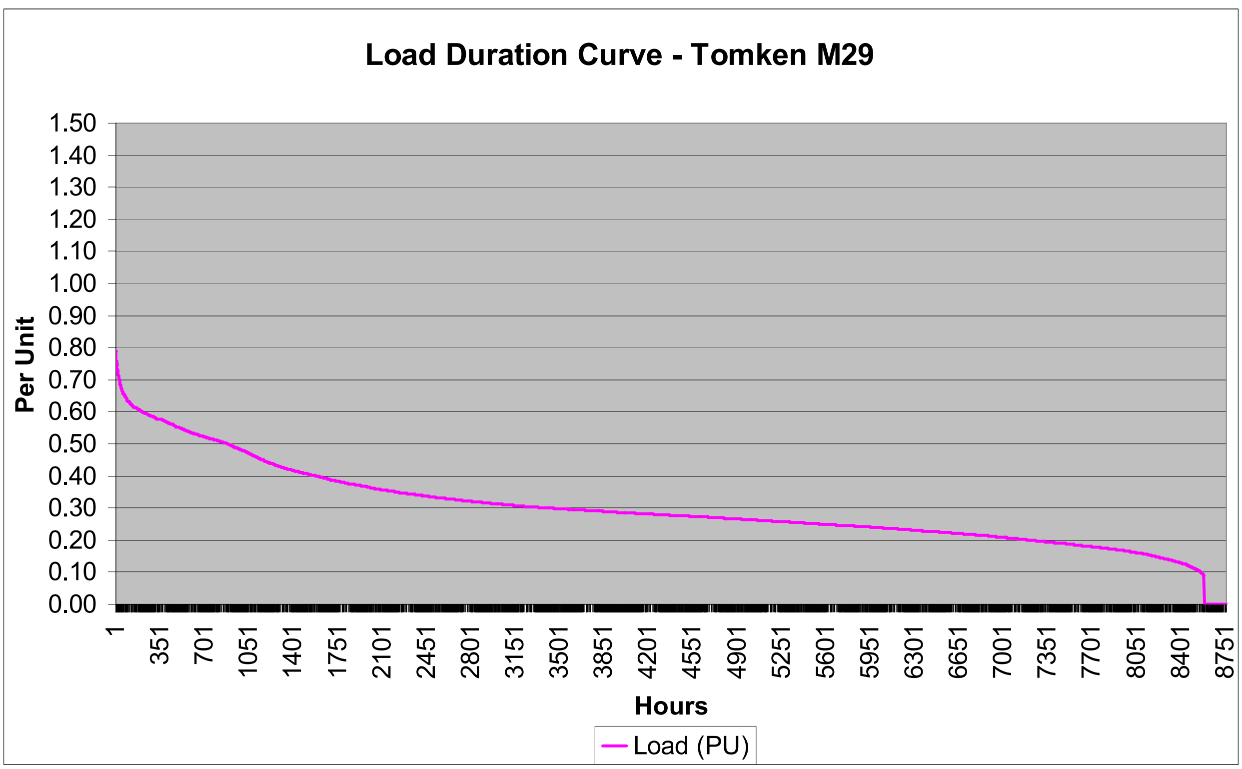
Hours
Load (PU)


Load Duration Curve - Tomken M29
Per Unit
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Hours
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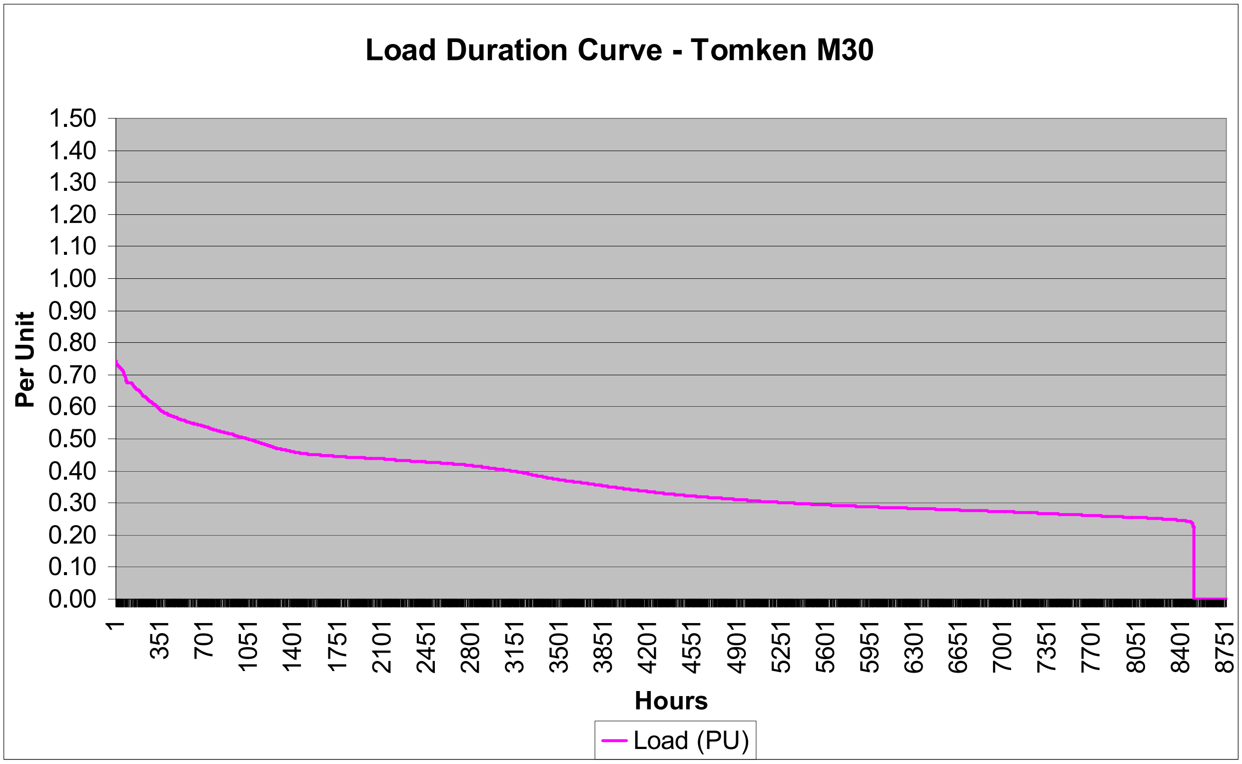
Load Duration Curve - Tomken M30
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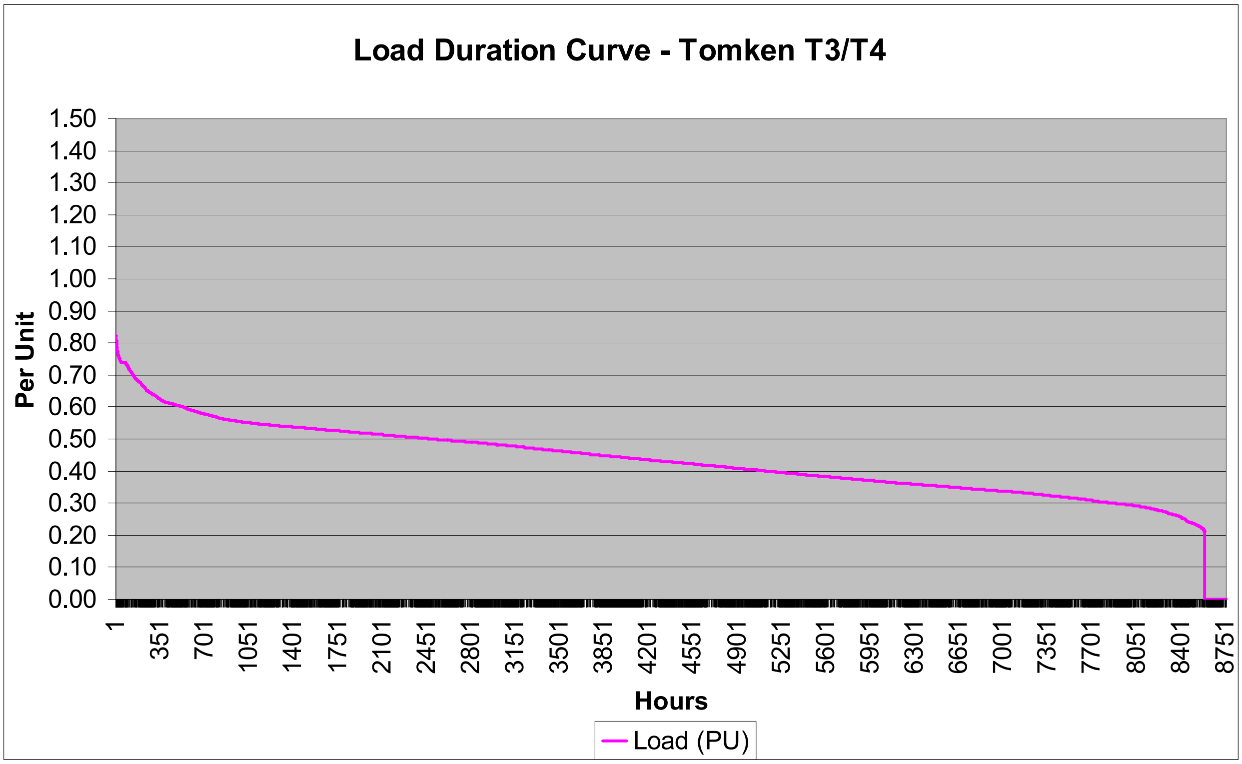
Hours
Load (PU)


Load Duration Curve - Tomken T3/T4
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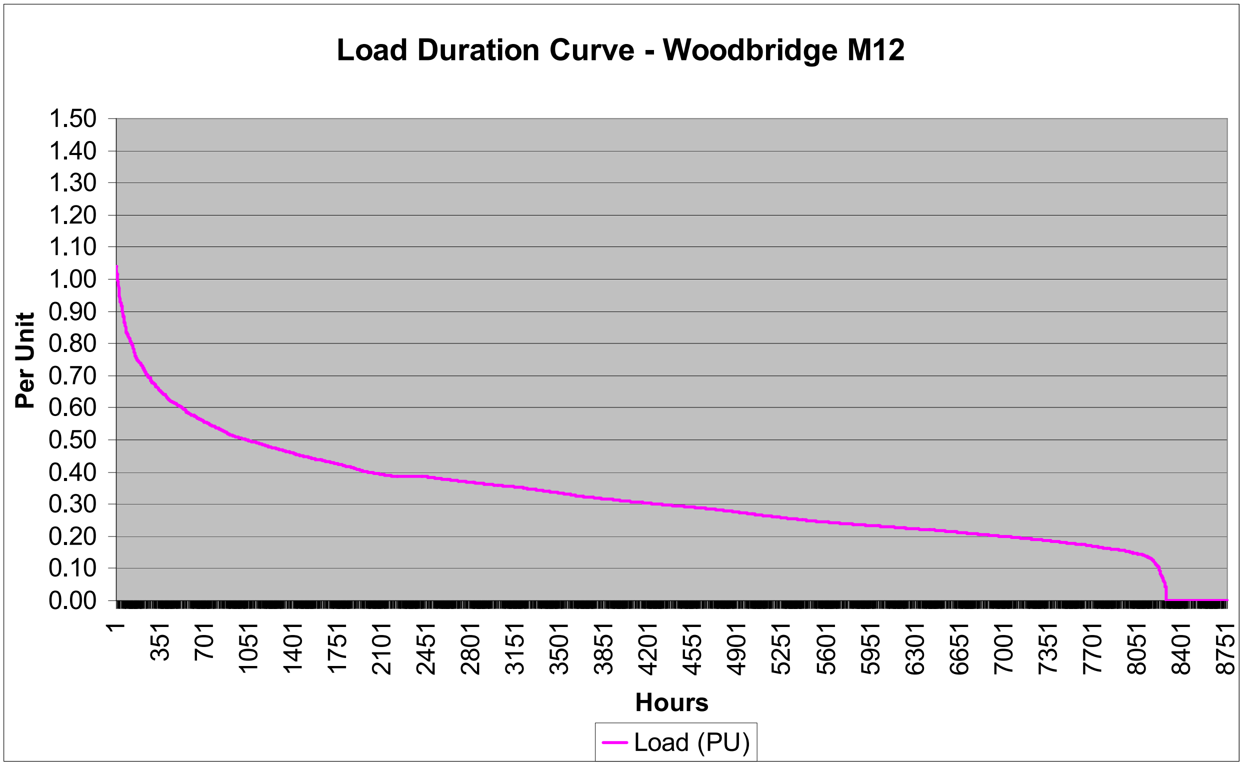
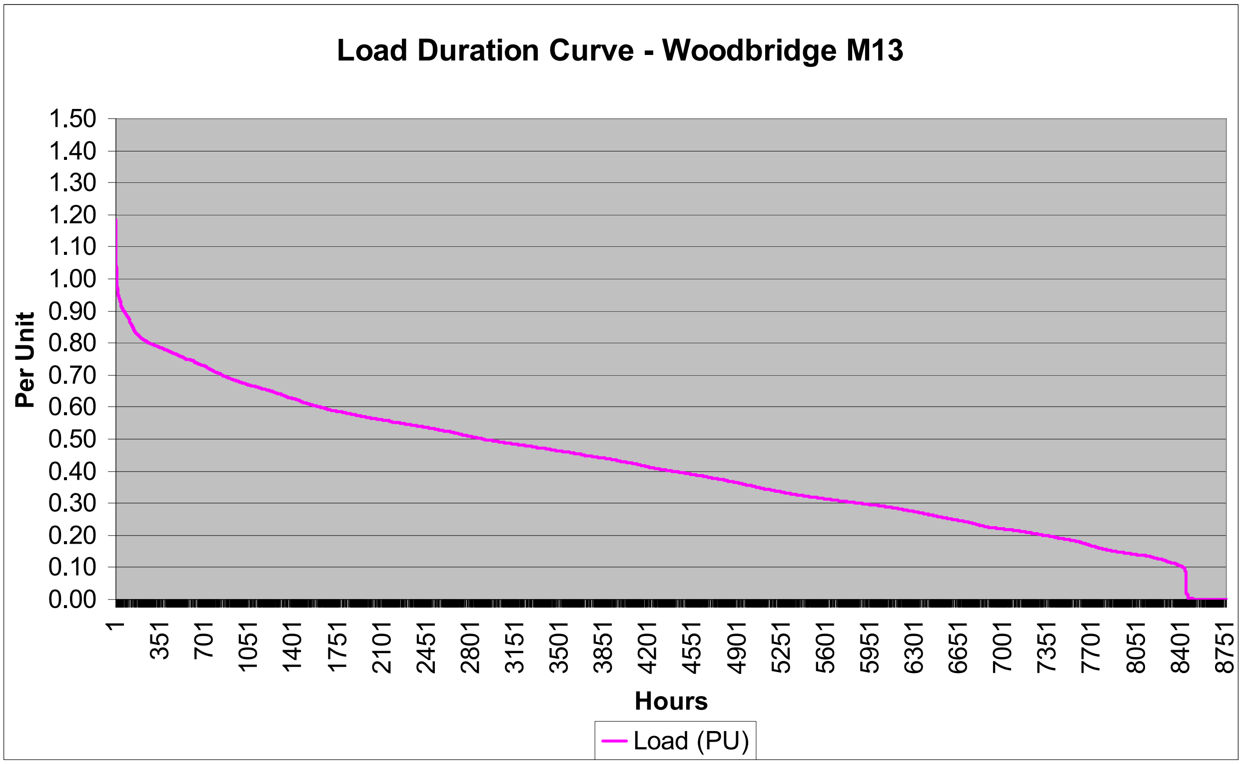
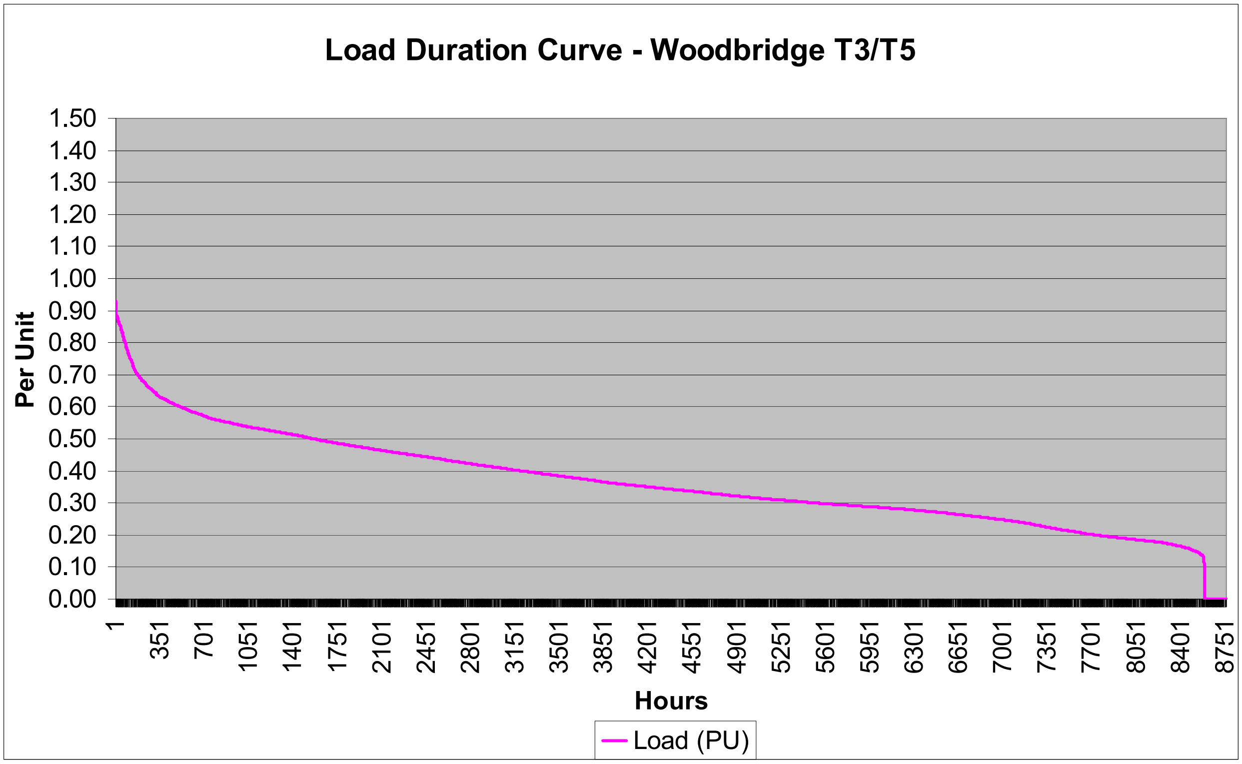
Hours
Load (PU)

Woodbridge TS







Load Duration Curve - Woodbridge T3/T5
Per Unit
1.50
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Hours
Load (PU)

Question 27

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/9] Please provide more detailed explanations of the budget increases proposed.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 28

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/11] Please provide an explanation of the budget overruns for the CIS system.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 29

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/13] Please provide an estimate of the average difference between expected in-service date and actual in-service date for capital projects over the last five years.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 30

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/20] Please provide a calculation of the impact on revenue requirement of using 11.6% for working capital, as Hydro One does, rather than 15% as proposed.

Response:

Enersource does not consider it appropriate to deviate from the Board endorsed methodology for computing the Allowance for Working Cash until an Enersource specific Lead-Lag study is conducted.

Question 31

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/32] Please provide a more detailed response to the IR.

Response:

Please refer to VECC technical conference response # 6.

Question 32

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/39] Please provide the historical and EDR numbers for each line item.

Response:

	2006 Historical	2006 EDR
Controllable Costs:		
Manpower	20,684	19,254
Materials	1,862	1,376
Transportation	986	983
Other	5,660	6,009
Subtotal Controllable Costs	29,174	27,622

Question 33

Reference SEC I/R #41.

Please file the source documents requested. A description is insufficient for this purpose.

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/42] Please provide the detailed formula for calculating incentives, including weightings, amounts (or range of amounts), 2007 targets/metrics, and examples of how the calculation works. Please file a copy of the actual incentive plan document detailing the rules of the plan.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 34

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/43] Please confirm that Enersource has no forecast of employee retirements, nor any plan to deal with those retirements, covering the period 2007-2010.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 35

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/43/Attach1] With respect to this document:

a. p.8. Please provide the basis for the assumption that 50% will retire at age 55. Please provide details of the applicant's past experience on percentage of employees that retire at age 55. Please advise the dollar impact of using retirement rate assumptions consistent with the prior report referred to in Attachment 2.

b. p.9. Please provide the source of the data in the table.

Response:

a. **The actuary developed the assumption that 50% of staff will retire at age 55, and Enersource can not comment on the basis for this assumption.**
b. **Enersource does not know the actuary's source for the data in the table.**

Question 36

Question sent Friday Nov 23, 2:20 pm

[Ref: J/D/43/Attach2] With respect to this document:

a. p.6. Please confirm that average salary, average age, and average service have gone down since July 2005. Please provide any reasons for this known to the applicant. If this is part of a plan to deal with an aging workforce, please provide the target age and experience level and when the applicant expects to reach that target.

b. p.7. Please provide a copy of the prior valuation referred to. Please advise the dollar impact of the change in retirement rate assumptions.

Response:

a. **Average salary has increased since July 2005. Average age and service have decreased slightly in the same period.**
b. **Please see attachment.**

March 2004

Enersource Corporation

Post-Retirement Benefits

Accounting Results
For the Fiscal Year Ending
December 31, 2003

www.watsonwyatt.com

Table of Contents

Section I
Introduction

Purpose of Report

Watson Wyatt Worldwide was engaged by Enersource Corporation to perform an actuarial valuation of post-retirement benefit liabilities and to determine the post-retirement non-pension benefit plan accounting results for the fiscal period starting Jan 1, 2003 and ending December 31, 2003.

This report presents the results of our actuarial valuation and outlines our calculation of the post-retirement benefit plan accounting results. These results were determined for the purpose of accounting for the cost of post-retirement benefits in the financial statements of Enersource Corporation. The results are also intended to inform management of the emerging cost of retiree benefits, to support ongoing monitoring of plan design and administration.

This report is not intended to be used for reporting to plan beneficiaries or for the funding or settlement of benefit obligations.

Basis for Results

The liability to be disclosed in the financial statements for the fiscal year ending December 31, 2003 and the formula for determining the 2004 benefit expense during the subsequent fiscal year are based on a new actuarial valuation with a measurement date of December 31, 2003. This valuation reflects:

- market discount rates as of December 31, 2003;
- post-retirement benefit plan employee and retiree data, as provided by Enersource Corporation as at December 31, 2003;
- post-retirement benefit plan provisions, including improvements adopted prior to December 31, 2003, as provided by Enersource Corporation

The post-retirement benefit plan liabilities have been determined as at December 31, 2003.

Our valuation includes a review of all of the data received for internal consistency and reasonableness. All dates were checked to ensure that they were valid and consistent with each other. For example, coverage amount as a percentage of salary must be consistent with the date of hire, and attained age must be reasonable. Any discrepancies uncovered during the course of our testing have been resolved by Enersource Corporation.

Section II
Valuation Results

Valuation Results as at December 31, 2003

Based on the employee and claims data in Section II, and the actuarial methods and assumptions described in Appendices A and B respectively, we have determined the valuation results shown in Exhibits I and II of Section IV, as at December 31, 2003.

Average Remaining Service Period of Active Employees

The average remaining service period is used to determine the minimum amortization of gains and losses. It reflects the plan membership and the assumed rates of retirement, termination of employment, and pre-retirement mortality. As at December 31, 2003, this average is 15.3 years.

Actuarial Valuation Results as at December 31, 2003

	Liability as at December 31, 2003				Service Cost for 2003	Expected Benefits for 2003
	Employees not fully eligible	Employees fully eligible	Retirees and Survivors	Total	Employees not fully eligible	
Life Insurance	405,900	390,000	1,081,800	1,877,700	30,500	71,000
Early Retirement Benefits	n/a	n/a	n/a	n/a	n/a	n/a
Total	405,900	390,000	1,081,800	1,877,700	30,500	71,000

Benefit Expense – 2004

As a result of the actuarial valuation as at December 31, 2003, we have determined the benefit expense for the fiscal year ending December 31, 2004 to be as follows:

Current Service Cost	$ 30,500
Interest Cost	$ 121,700
Expense Total	$ 152,200

Sensitivity Analysis

The liability and service cost calculations are dependent on the actuarial assumptions chosen, as outlined in Appendix C. The setting of the discount rate can often have a significant impact on the determination of the actuarial accrued liability. The impact on the actuarial accrued liability of a 25 basis-point increase in the discount rate is summarized below.

	Current Assumption	Alternative	Impact on Liability
Discount Rate	6.5%	6.25%	3.8%

Section III
Actuarial Opinion

This valuation of post-retirement non-pension benefit liabilities was performed for the purpose of reporting in the financial statements of Enersource Corporation for the period ending December 31, 2003.

To the best of our knowledge, all benefit provisions considered in this report are up to date, and there have been no material changes to the post-retirement benefits between December 31, 2003 and the date of this report that were not reflected in the results.

The actuarial method used in developing the Accrued Benefit Obligation and current service cost is in accordance with the requirements as set out in Section 3461 of the Canadian Institute of Chartered Accountants' Handbook - Accounting.

The actuarial assumptions used in developing the Accrued Benefit Obligation and current service cost are management's best estimate assumptions established by Enersource Corporation with our assistance. In our opinion these assumptions are reasonable and appropriate for the purposes of this report.

In our opinion, the actuarial methods employed in our calculations are consistent with sound actuarial principles.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice.

If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,
Watson Wyatt Worldwide

Paul Serafini
Fellow, Canadian Institute of Actuaries

March 15, 2004
Toronto, Ontario

Section IV
Accounting Results

Exhibit I

Enersource
2004 CICA 3461 Benefit Expense
Post-retirement Life
(All Amounts in Canadian Dollars)
6.50% Discount Rate

Balance Sheet Reconciliation as at January 1, 2004	
Accumulated Post Retirement Benefit Obligation	1,877,700
Plan Assets	-
Funded Status	(1,877,700)
Unamortized Initial Transition Obligation	-
Unamortized Prior Service Cost	-
Unamortized Experience (Gains) and Losses	93,300
Accrued Post Retirement Benefit Cost	(1,971,000)
2004 Benefit Expense	
Service Cost	30,500
Interest Cost	121,700
Amortization of Initial Transition Obligation	-
Amortization of Past Service Costs	-
Amortization of Experience (Gains)/Losses	-
Periodic Expense	152,200
Curtailment (Gain)/Loss	-
Total expense	152,200
Development of Accrued Benefit Cost	
Accrued Benefit Cost at January 1, 2004	1,971,000
2004 Total Expense	152,200
Less Expected Claims	71,000
Accrued Benefit Cost at December 31, 2004	2,052,200
EARSL	15.3

Exhibit II

Enersource
Post-Retirement Benefits Other Than Pensions
Year End Disclosures in Accordance with CICA 3461
(All Amounts in Canadian Dollars)

Benefit Expense	*2003*
Current service cost	30,000
Interest cost	128,600
Expected return on plan assets	-
Amortization of transition obligation	-
Amortization of past service costs	-
Amortization of net actuarial loss	-
Benefit plan expense	158,600
Curtailment (gain)/loss	-
Net benefit plan expense	158,600

Disclosure Information as at December 31	*2003*
Accrued benefit obligation -	
Balance at beginning of year	1,710,400
Current service cost	30,000
Interest cost	128,600
Benefits paid	(65,300)
Actuarial losses (gains)	74,000
Plan Amendments	-
Acquisitions	-
Divestitures	-
Balance at end of year	1,877,700
Plan assets	
Fair value at beginning of year	-
Actual return on plan assets	-
Employer contributions	65,300
Benefits paid	(65,300)
Plan Amendments	-
Acquisitions	-
Divestitures	-
Balance at end of year	-
Funded status - plan surplus (deficit)	(1,877,700)
Unamortized net actuarial loss (gain)	(93,000)
Unamortized past service costs	-
Unamortized transitional obligation	-
Accrued benefit cost	(1,970,700)

Significant actuarial assumptions:	
Discount rate	6.50%
Rate of compensation increase	3.50%

Health Care Trend Rate Assumption not applicable as
APBO includes only life insurance benefits

Appendix A
Summary of Benefit Provisions

Eligibility

Retirement benefits are paid to employees who retire from active service with Enersource Corporation after having attained age 55 and completed two years of service and who are receiving a pension.

Employees who are temporarily disabled continue to be eligible for benefits under the benefits plan for active employees. No provision is made for this benefit.

Life Insurance

Employees who retire prior to age 65 are eligible for life insurance based on the date of employment and years of service. The schedule of coverage is as follows:

Employees who were hired prior to April 1, 2000:

a) Employees age 55 and over with less than 10 years of service receive $2,000 life insurance.

b) Employees age 55 and over with 10 or more years of service receive life insurance as a percentage of final salary:

- 105% if hired prior to May 1, 1967 and never opted for additional life insurance under options 2, 3, or 4;
- 50% if hired between May 1, 1967 and January 1, 1980 and never opted for additional life insurance under options 2, 3, or 4;
- 50% graded down to 25% over 10 years if at any time employees elected additional life insurance under option 2, 3, or 4;

Employees who were hired on or after April 1, 2000:

c) Employees age 55 and over with less than 10 years of service receive a paid-up life insurance policy in the amount of $5,000.

d) Employees age 55 and over with 10 or more years of service receive a paid-up life insurance policy in the amount of $10,000.

Appendix B
Employee and Beneficiary Data Statistics

The following individuals are current or potential future beneficiaries of the retiree benefits plan, as at December 31, 2003.

Group	Number	Average Age	Average Earnings	Percentage Female
Active employees fully eligible for benefits (i.e. over age 55 and at least ten years' service)	53	56.62	99,533	28%
Active employees not fully eligible for benefits	270	44.85	62,015	28%
Retired employees	102	70.33	40,569 [1]	41%

[1] *Amount shown is average coverage in force for retired employees.*

Appendix C
Actuarial Assumptions and Methods

An actuarial valuation of post-retirement benefits provides a reasonable and systematic allocation of the cost of future benefits to the years in which the related employees' services are rendered. In order to value the liabilities of the post-retirement benefits, it is necessary to:

- make assumptions as to discount rates, health care cost trend rates, inflation, mortality and other decrements;
- use these assumptions to calculate the present value of expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to specific years of employment.

Actuarial Cost Method

The Accrued Benefit Obligation and current service cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by Paragraph 3461.034 of the Canadian Institute of Chartered Accountants' Accounting Recommendations when future salary levels or cost escalation affect the amount of employee future benefits. Under this method, the projected post-retirement benefit is deemed to be earned on a pro-rata basis over the years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits. For this plan, the attribution period ends upon the later of attainment of age 55 and completion of two years of service.

For each employee not yet fully eligible for benefits, the Accrued Benefit Obligation is equal to the present value of expected future benefits multiplied by the ratio of years of service to date to total years of service in the attribution period. The current service cost is equal to the present value of expected future benefits multiplied by the ratio of years of service in the fiscal period to total years of service in the attribution.

For each retired employee, each dependant or survivor of an retired employee, and each active employee who is fully eligible for benefits, the Accrued Benefit Obligation is equal to the entire present value of expected future benefits (commencing at retirement or pre-retirement death), and there is no current service cost.

The total Accrued Benefit Obligation and the total current service cost are determined by summing these amounts for all individuals.

Actuarial Assumptions Specific to the Measurement Date

Discount Rate

The interest rate used to discount life insurance benefits was 6.50% per annum. This rate reflects the yield on high quality corporate bonds, as at December 31, 2003.

Long-Term Actuarial Assumptions

Salary Increases

Salaries were assumed to increase at the rate of 3.50% per annum plus.

Mortality

Mortality was assumed to be in accordance with the 1994 Uninsured Pensioners Mortality Table.

Rates of Termination

Selected rates of termination of employment prior to full eligibility for reasons other than death are shown below:

Age	Rate
25	.0835
35	.0467
45	.0237
55	.0068

Disability

12% of the rates from Railroad Retirement Board – 12th Valuation.

Age	Rate Per Thousand of Members
25	0.144
35	0.180
45	0.660
55	2.08

Rates of Retirement

	Calendar Year		
Age	2000-2001	2002	2003+
50	0.0600	0.0000	0.0000
51	0.0600	0.0000	0.0000
52	0.0600	0.0000	0.0000
53	0.0600	0.0000	0.0000
54	0.0600	0.0000	0.0000
55	0.0600	0.0600	0.0446
56	0.0600	0.0600	0.0446
57	0.0600	0.0600	0.0446
58	0.0600	0.0600	0.0446
59	0.0600	0.0600	0.0446
60	0.1065	0.1065	0.1065
61	0.1065	0.1065	0.1065
62	0.1074	0.1074	0.1074
63	0.1183	0.1183	0.1183
64	0.1305	0.1305	0.1305
65	1.0000	1.0000	1.0000

Expenses and Taxes

Expenses and taxes were assumed to be 15.7% per year. This assumption reflects current tax rates and province of residence of current plan beneficiaries.

Question 37

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/44] Please provide the reconciliation requested.

Response:

Please find below a reconciliation of the 2006 Historical Actual data as reported in Exhibit D / Schedule 2 / Tab 1 and Enersource's 2006 Financial Statements.

Operations, Maintenance and Administrative Expenses (000's)

	Actual 2006	Financial Statement Actual 2006
Controllable Costs:		
Manpower	20,684	20,684
Materials	1,862	1,862
Transportation	968	968
Other	5,660	5,660
Subtotal Controllable Costs	29,174	29,174
CDM operating expenses	1,906	1,906
Other Expenses	2,577	2,577
Bad Debt Expense	2,580	2,580
Management Fees/Recoveries	(338)	(338)
Total Financial Statement - Operations, maintenance and admin	35,899	35,899
Less: Non-Distribution Expenses/Revenue Reclass	(438)	-
Total	35,461	35,899
Add: Capital Taxes	1,557	1,557
Subtotal	37,018	37,456
Amortization of capital assets	30,275	30,275
Amortization of regulatory assets	7,144	7,144
Total Distribution Expenses	74,437	74,875

Question 38

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/47-55] At the Technical Conference, we will take you through these charts and seek explanations for the several most material numbers.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 39

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/55-58] On October 3, 2006 the Board approved an increase in 2006 rates of $1,130,601 (and a resulting increase of $1,140,776 in 2007 due to the PBR structure) on the basis that in 2004 the applicant had 38 vacant positions, rather than 15 as it normally would. Please list the 38 positions vacant in 2004, with descriptions similar to this IR response, then advise when each was filled, when each became vacant again, if it did, and reconcile the total of $2,271,377 in incremental rates in 2006 and 2007 to the additional amounts expended on those new hires in those years. If any of those hires are listed in pages 55-58, please indicate. If any of those hires, while not the same as those listed in these pages, has a similar position name or function, please distinguish the old hire from the new one.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 40

Reference SEC I/R #12.

Please provide the dates of any conference calls or similar investor/analyst communications by Enersource Hydro or Enersource Corporation. Please provide transcripts and audio tapes of Enersource Corporation conference calls or similar communications. If transcripts and audio tapes have been destroyed, please provide a list of those known to be on the calls, so that we can seek copies of the disclosures from them.

Question sent Friday Nov 23, 2:20 pm

Ref: J/A/63-64] Please provide the Board minutes referred to. Please provide any variance explanations provided to the Board or senior management with respect to material overspending.

Response:

Enersource does not conduct investor/analyst communications and accordingly is unable to provide the requested dates, transcripts, audio tapes or list of calls.

Question 41

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/66] Please provide full details on the compensation paid or payable to all Enersource Corporation board members, and show the portion of those amounts allocated to Enersource Hydro Mississauga.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 42

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/unnumbered between pages 67 and 68] Please provide the actual notice of assessment showing dollar figures rather than zeros throughout.

Response:

The Corporation Notice of Assessment provided is the actual notice of assessment for the taxation year-end December 31, 2006.

Question 43

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/72] Please calculate 2008 PILs using the proposed newly announced)but not yet enacted) federal income tax rates, the proposed new CCA rates, and treating the CIS as a Class 12 asset. Please do a further calculation of the PILS on that same basis, but with a long-term debt rate on 56% of rate base at 6.29%, a short-term debt rate on 4% of rate base at 4.59%, and ROE on 40% of rate base at 8.39%. Please provide the revenue requirement impacts of each of these two alternative PILs calculations.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 44

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/73] Please provide details of the tax audit in 2006 and the reassessment that resulted.

Response:

Please find attached details on the tax audit in 2006.

Ontario

Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Account No.
1800247

35 A
PX5000

ENERSOURCE HYDRO MISSISSAUGA INC.
C/O BARRY LEWIS
3240 MAVIS RD

MISSISSAUGA ON
L5C 3K1

Taxation Year End: (YYYYMMDD)	20031231
Payment Amount: $	5,037.75
Taxation Year End: (YYYYMMDD)	20061231
Payment Amount: $	
Total Payment Enclosed: $	5,037.75

Ontario

Ministry of Finance
Corporations Tax Branch - Hydro PIL
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Keep this portion for your records.

Statement of Account

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
for transactions up to and including 2006/06/16

	Account No.	Statement Date (year, month, day)	Page
ENERSOURCE HYDRO MISSISSAUGA INC.	**1800247**	2006/06/16	1 of 2

TRANSACTIONS BY ASSESSED TAXATION YEAR

EFFECTIVE DATE	ID NUMBER	DESCRIPTION	AMOUNT	BALANCE
2002/11/13		OPENING BALANCE FOR: 2001/12/31	0.00	
2002/10/04	96	assessment reversal	624,987.00CR	
2002/10/04	98	interest reversal - assessment	30,145.99	
2002/11/12	99	interest reversal	1,083.31	
2006/06/13	97	reassessment	629,971.00	
2006/06/13	100	interest - assessment *	31,161.73CR	5,051.57
2005/10/04		OPENING BALANCE FOR: 2002/12/31	0.00	
2005/09/08	101	reassessment reversal	2,875,908.00CR	
2005/09/08	103	interest reversal - assessment	45,154.40	
2005/09/09	104	interest reversal	14.58	
2005/10/03	105	interest reversal	248.07	
2006/06/13	102	reassessment	3,144,632.00	
2006/06/13	106	interest - assessment *	9,448.13CR	
2006/06/16	113	interest *	200.39	304,893.31
2005/10/04		OPENING BALANCE FOR: 2003/12/31	0.00	
2005/09/08	109	interest reversal - assessment	29,294.94	
2005/09/09	110	interest reversal	7.02	
2005/10/03	111	interest reversal	119.45	
2006/06/16	112	cascade interest	24,383.66CR	5,037.75
2005/09/10		OPENING BALANCE FOR: 2004/12/31	0.00	
2005/09/09	107	cascade interest - reversal	28,307.86	
2006/06/16	108	cascade interest	28,307.86CR	0.00
BALANCE DUE **				314,982.63

TRANSACTIONS BY UNASSESSED TAXATION YEAR

2006/06/03	OPENING BALANCE FOR: 2005/12/31	10,410,110.22CR	
BALANCE		10,410,110.22CR	
2006/06/03	OPENING BALANCE FOR: 2006/12/31	4,320,157.90CR	
BALANCE		4,320,157.90CR	

Ontario

PO Box 622
33 King St. West
Oshawa ON L1H 8H6

CP 622
33 rue King ouest
Oshawa ON L1H 8H6

Statement of Adjustments re Taxes Assessec
Relevé des redressements de cotisations

Ministry of Finance
Ministère des Finances

Corporations Tax Branch
Direction de l'imposition des compagnies

Name of Corporation / Raison sociale de la compagnie	Account No. / N° de compte: 1 8 0 0 2 4 7
Enersource Hydro Mississauga Inc.	Taxation Year End / Fin de l'année d'imposition: 31 December 2001

INCOME TAX

	Federal	Ontario	
Loss as previously assessed	($ 12,488,026)	($ 12,488,026)	
Less: Misc. expenses disallowed	137,130	137,130	
Bad Debt expense disallowed	627,402	627,402	
PST penalty disallowed	5,240	5,240	
Revised Loss	($ 11,718,254)	($ 11,718,254)	

Ontario and Federal Income Tax

Tax thereon		$ Nil

CAPITAL TAX

Paid up Capital previously filed	$ 479,210,505	
Add: Other Reserves	1,765,507	
Decrease in NBV/UCC differences	2,136,728	
Revised Paid up Capital	$ 483,112,740	
Deduct: Investment Allowance	Nil	
Revised Taxable Capital	$ 483,112,740	
Deduct: Capital Tax Exemption	4,833,533	
	$ 478,279,207	- Rate? .07%
Ontario Capital Tax @ 0.3% x 92/365 days		361,658

DRAFT

Federal Part 1.3 Tax

Taxable Capital	$483,112,740	
Deduct: Capital Deduction	10,000,000	
	$473,112,740	Rate? .5%
Gross Part 1.3 tax @ .225% x 92/365 days		268,313

TOTAL PAYMENT IN LIEU OF TAXES	$ 629,971

Sandra Molinaro
MRK887

*"DESIGNATED ASSESSMENT"

The items marked with an asterisk above are designated parts of this assess-ment. This description is authorized by section 92 of the Corporations Tax Act, for assessments which correspond to those issued by Revenue Canada under the Income Tax Act (Canada). It is not necessary to serve a Notice of Objection to those portions of the assessment. The Corporation and the Minister will be bound by the final disposition of a federal Notice of Objection or Appeal.

If you wish not to be bound by the disposition of the corresponding federal objection or appeal, you must serve a Notice of Objection on the prescribed form in accordance with section 84. See under "Notice of Objection" on the accompanying "Notice of Re-Assessment"

*"COTISATION DÉSIGNÉE"

Les postes ci-dessus marqués d'un astérisque sont les parties désignées de cette cotisation. Cette description est autorisée en vertu de l'article 92 de la Loi sur l'imposition des corporations, pour les cotisations qui correspondent à celles établies par Revenu Canada en vertu de la Loi de l'impôt sur le revenu (Canada). Il n'est pas nécessai de signifier un Avis d'opposition pour ces parties des cotisations. La compagnie et le ministre seront liés par la décision finale relative à l'avis fédéral d'opposition ou d'appel.

Si vous désirez ne pas être lié par la décision relative à l'opposition ou à l'appel fédéral correspondant, vous pouvez signifier un avis d'opposition sur la formule prévue à cette fin conformément à l'article 84. Voir "Avis d'opposition" sur l'Avis de nouvelle cotisation ci-joint.

Ontario

PO Box 622
33 King St. West
Oshawa ON L1H 8H6

CP 622
33 rue King ouest
Oshawa ON L1H 8H6

Statement of Adjustments re Taxes Assessed
Relevé des redressements de cotisations

Ministry of Finance
Ministère des Finances

Corporations Tax Branch
Direction de l'mposition des compagnies

Name of Corporation / Raison sociale de la compagnie Enersource Hydro Mississauga Inc.	Account No. / N° de compte 1 8 0 0 2 4 7
	Taxation Year End / Fin de l'année d'imposition 31 December 2002

INCOME TAX

	Federal	Ontario	
Taxable Income as previously assessed	$ 12,953,087	$ 12,953,087	
Add: Bad Debt Expense disallowed	116,264	116,264	
Misc. expenses disallowed	17,420	17,420	
Less: Application of prior period non-capital loss	(11,718,254)	(11,718,254)	
Bad Debt expense allowed	(83,218)	(83,218)	
Revised Taxable Income	$ 1,285,299	$ 1,285,299	
Revised Federal Income Tax			
Part I tax @ 38%	$ 488,414		
Deduct: Federal tax abatement @ 10%	(128,530)		
	$ 359,844		
Add: Corporate surtax @ 4%	14,394		
Deduct: General Tax Reduction for CCPCs	(38,559)		
Part I Tax Payable			$ 335,719
Revised Ontario Income Tax			
Tax thereon @ 12.5%			160,662

Revised CMT Payable

CMT Base $4,647,320 x 4% =	Gross CMT Payable	$ 185,893	
	Less: Income Taxes	(160,662)	
	Net CMT Payable		25,231

DRAFT

Continued ... /2

*"DESIGNATED ASSESSMENT"
The items marked with an asterisk above are designated parts of this assess-ment. This description is authorized by section 92 of the Corporations Tax Act, for assessments which correspond to those issued by Revenue Canada under the Income Tax Act (Canada). It is not necessary to serve a Notice of Objection to those portions of the assessment. The Corporation and the Minister will be bound by the final disposition of a federal Notice of Objection or Appeal.

If you wish not to be bound by the disposition of the corresponding federal objection or appeal, you must serve a Notice of Objection on the prescribed form in accordance with section 84. See under "Notice of Objection" on the accompanying "Notice of Re-Assessment"

*"COTISATION DÉSIGNÉE"
Les postes ci-dessus marqués d'un astérisque sont les parties désignées de cette cotisation. Cette description est autorisée en vertu de l'article 92 de la Loi sur l'imposition des corporations, pour les cotisations qui correspondent à celles établies par Revenu Canada en vertu de la Loi de l'impôt sur le revenu (Canada). Il n'est pas nécessaire de signifier un Avis d'opposition pour ces parties des cotisations. La compagnie et le ministre seront liés par la décision finale relative à l'avis fédéral d'opposition ou d'appel.

Si vous désirez ne pas être lié par la décision relative à l'opposition ou à l'appel fédéral correspondant, vous pouvez signifier un avis d'opposition sur la formule prévue à cette fin conformément à l'article 84. Voir "Avis d'opposition" sur l'Avis de nouvelle cotisation ci-joint.

Enersource Hydro Mississauga Inc.
Account No. 1800247

31 December, 2002

CAPITAL TAX

Federal Part 1.3 Tax

Taxable Capital	$ 502,657,000	
Add: NBV/UCC decrease	10,238,159	
	$ 512,895,159	
Deduct: Capital Deduction	10,000,000	
	$ 502,895,159	
Gross Part 1.3 tax @ .225%	$ 1,131,514	
Deduct: Surtax	14,394	
		$ 1,117,120

Ontario Capital Tax

Paid up Capital previously filed	$ 505,486,785	
Add: NBV/UCC decrease	10,238,159	
Revised Paid up Capital	$ 515,724,944	
Deduct: Investment Allowance		
$\frac{\$\ 10,026,000}{\$\ 583,161,852}$ X $515,724,944	(8,866,592)	
Revised Taxable Capital	$ 506,858,352	
Deduct: Capital Tax Exemption	4,891,567	
	$ 501,966,785	
Tax thereon @ 0.3%		1,505,900
TOTAL PAYMENT IN LIEU OF TAXES		$ 3,144,632

Sandra Molinaro
MRK887

Question 45

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/78/Account 190] Please explain why this is not allocated in the same manner as the original costs in the regulatory assets accounts.

Response:

With respect to this question, we assumed that your reference [Ref:/J/A/78/Account 190] is referencing Account 1590.

Enersource has assigned allocation responsibility by customer class to Account 1590 and all other accounts, with the exception of LRAM and SSM claims, in a methodology that is consistent with the 2006 EDR Application. Enersource assigned responsibility for the recovery of the LRAM claim based on kWh savings realized by the subject customer class. Enersource assigned responsibility for the recovery of the SSM claim based on the computed responsibility for each customer class.

Question 46

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/82/Attach2] Please provide the number of participants that were schools, the savings for those participants, and the incentive paid to those participants, for each program listed.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 47

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/94] Please confirm that, if the approved capital structure for 2008 is:

a. 56% long term debt at 6.29%
b. 4% short term debt at 4.59%
c. 40% equity at 8.39%

the weighted average cost of capital is 7.06%, and the reduction in revenue requirement is $2,731,589 or 2.19%.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 48

Question sent Friday Nov 23, 2:20 pm

[Ref: J/A/101] Please refile the Bill Impacts in Exhibit H, Schedule 5 on the basis that rates are set in 2008 to comply with the following cost allocation and rate design principles:

d. No class has a revenue to cost ratio of greater than 110%
e. The streetlighting revenue to cost ratio is set at 90%
f. The revenue to cost ratios of the Residential and the GS 500-4999 classes are proportionately increased to adjust for the above changes, and
g. The fixed charge in GS<50 class is set to recover 50% of the class responsibility for revenue requirement.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 49

Question sent Friday Nov 23, 2:20 pm

[Ref: J/E/2/Attach1//p6] Please identify all costs related to the CIS and risk management in 2006 and 2007 that would otherwise have been captured by the deferral accounts requested, and show how those costs have been dealt with in this application.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 50

Question sent Friday Nov 23, 2:20 pm

[Ref: J/E/3b] Please advise the sources of the performance criteria in use by Enersource, other than comparison with neighbouring distributors.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Question 51

Question sent Friday Nov 23, 2:20 pm

[Ref: J/E/21] Please provide greater details on the range of $35-$72 million for cost of power, and the range of $9-$18 million for other regulated charges. Please provide, if available, a monthly chart of those actual figures for 2006 and 2007 to date, together with any monthly forecast for 2008 in the applicant's possession.

Response:

Please refer to response in SEC #30.

Other Questions asked by Email on November 16

Reference SEC I/R #20.

Please provide any business case or planning document listing the actions planned, the costs, and/or the benefits in the test year or other future years.

Response:

Please find below the planning document associated with the upgrade of the current i-doxs software.

EHM is currently working on a Statement of Work for the implementation of a version up-grade of the i-doxs software with Kubra. One of the new features of this up-grade is a convenience fee model which will allow our customers to make payments a) via the web, b) over the phone or c) with a CSR using Visa or MasterCard. Kubra currently maintains and administers this service for other customers, and as such EHM is interested pursuing a service agreement with Kubra. At this time, it is expected that all costs associated with implementing and maintaining the new convenience fee model will be borne by Kubra. A convenience fee of $4.95 per transaction is levied for each incremental $500. This new module will be investigated and scoped for customer presentation after the up-grade of the base software is completed. The expected review is the third quarter of 2008.

Costs

The planned version upgrade of the current i-doxs software is $40,000, which was planned in the 2008 Rate Application. With regards to the convenience fee model EHM has not included any budgeted amount in the 2008 Rate Application. At this time, it is expected that all costs associated with implementing and maintaining the new convenience fee model will be borne by Kubra. EHM anticipates that the number of customers using this service will be minimal given the customer convenience fee of $4.95 for each transaction in increments of $500. It is expected that this new convenience fee model will be investigated and scoped in late 2008.

Benefits

Should the Visa / Mastercard convenience fee model be presented to our customers, EHM anticipates that collection charges, late payment charges and bad debt expense may be minimally impacted in 2009 onward. EHM is unable to determine any projected impacts from the implementation of this new service, and as such did not reduce its collection charges, late payment charges, or bad debts.

Should the Visa / Mastercard convenience fee model be presented to our customers, EHM will monitor the impact of this program on collection charges, late payment fees, and bad debts to be in a better position to accurately forecast any impacts on collection charges, late payment charges and bad debts expense.

EHM PROJECT BUSINESS CASE	
INVESTMENT CATEGORY:	IT System Requirement
INVESTMENT NAME:	Kubra i-doxs Suite V3.8 Up-Grade
PROJECT NAME:	Kubra i-doxs Suite V3.8 Up-Grade

Business Need:

The Information Technology capital budget is used to provide information technology tools to assist our personnel in managing our field assets throughout the life cycle and providing our customers excellent customer service.

Upgrading to the vendor's current release of the i-doxs Suite will allow Enersource to investigate and test new features, while providing our customers an improved level of service on the base product.

The risk of not up-grading our software is termination of vendor support.

Investment Summary:

Software Up-grade: Included in Maintenance Agreement
Implementation: $40,000

The Statement of Work is expected to be completed by Q1 of 2008 with an implementation schedule of Q3 2008.

Note: Although the version up-grade will be implemented in its entirety, further scoping of the new features is required.

Results:

Up-grade of current system ensuring vendor support.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008		

Capital Costs	**$40**		

Other Questions asked by Email on November 16

Reference SEC I/R #22.

We do not understand the answer. At the Technical Conference, we will ask you to walk us through this so that we understand better both the numbers and the methodology.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Other Questions asked by Email on November 16

Reference SEC I/R #35D.

Please file the data requested, in confidence if necessary.

Response:

Enersource is unable to provide a written response due to limited time and resources.

Enersource Mississauga Hydro Inc. (Enersource)
2008 Electricity Rate Application
Board File No. EB-2007-0706

VECC's Technical Conference Issues

I. Rate Base

Question #1
-Reference: i) VECC #18

Preamble:

When "business cases" were requested in parts (a) and (c) of this question, what was being sought were Project Business Cases similar to what are contained in C/5/1 (i.e., what is the "business reason" for the expenditure?).

(a) With respect to the 2007 projects that are listed in Appendix A of C/4/1, are there business case descriptions for those where the costs exceed Enersource's materiality limit? If so, please provide.

(b) Please provide a schedule listing all 2008 capital projects – similar to the one provided for 2007 in Appendix A (C/4/1).

(c) Does C/5/1 contain the "business cases" for all major 2008 capital projects?

(d) The sum of the 2008 costs for Overhead Distribution Upgrade projects (C/5/1) appears to be \$3.2 M which exceeds the \$2.6 M (C/2/2, page 9) total in the Application – please reconcile.

Response: 1. a)

Please refer to VECC interrogatory # 18.

Response: 1. b)

VECC #1 (b)

SUMMARY LISTING OF 2008 CAPITAL PROJECTS

Item	Description		2008 Budget Amount
	SUBTRANSMISSION/DISTRIBUTION		
1	44kV - Cawthra Rd - Dundas St to Bloor MS	$	500,000
2	3 - 8/ 13.8kV - Chinook Ph 1		600,000
3	44kV - Meadowvale TS Feeder Relief - TS to WCB & the railway tracks		950,000
4	44kV - Bramalea TS Feeder Relief - 74M49 CB to Bramalea Rd to Drew Rd		800,000
5	44kV - Winston TS Egress Feeders Ph 1 - Ninth Line to WCB		1,850,000
6	16/ 27.6kV - WCB - Royal Windsor to Lakeshore then to Avonhead		750,000
7	8/ 13.8kV - Etude - Goreway to Cambrett Dr		400,000
	Total Subtransmission/Distribution	**$**	**5,850,000**
	SUBDIVISION REBUILDS		
1	Inverhouse	$	1,300,000
2	Winwood Drive		1,300,000
3	Pheasant Run		1,000,000
4	Council Ring Phase II		1,000,000
5	Falconer Drive		1,000,000
6	Misc.		500,000
	Total Subdivision Rebuilds	**$**	**6,100,000**
	SUBSTATIONS		
1	Confederation MS - add tx, cabling	$	300,000
2	New # 90 at WCB/ Hwy 401		700,000
3	Bromsgrove MS - reclosures & automation		300,000
4	Protection Relays - McNeice		50,000
5	Protection Relays - Melton		50,000
6	Bexhill MS upgrade		650,000
7	Century T2 - add tx & new HV breaker		350,000
8	Grossbeak T2 - new tx & HV breaker		525,000
9	Spare offload tx		400,000
10	Substation Site Enhancements		100,000
	Total Substations	**$**	**3,425,000**
	AUTOMATED SWITCHES AND SCADA		
1	Automation at various MS's	$	700,000
2	Automation at various feeders		700,000
	Total Automated Switches and SCADA	**$**	**1,400,000**
	SYSTEM MAINTENANCE PROJECTS		
1	Wood & Concrete Pole Replacement		824,000
2	Overhead Switch and Insulator Replacement		464,000
3	Feeder Overhaul		386,000
4	Overhead Rebuild		926,000
5	Primary Distribution Equipment Replacement		700,000

6	Underground Cable and Splice Replacement	1,375,000
7	Meter Base Replacements	50,000
8	Secondary Cable Replacements	75,000
9	Underground Transformer Replacement	420,000
10	Overhead Transformer Replacement	230,000
	Total System Maintenance Projects	**5,450,000**
	Other Capital	
1	Road Projects	750,000
2	New Industrial/Commercial Customers	4,200,000
3	New Subdivisions	2,575,000
4	Major Tools	150,000
5	Rolling Stock	1,857,600
	Total Other Capital	**9,532,600**
	TOTALS	
	Total - Subtransmission/Distribution	5,850,000
	Total - Subdivision Rebuilds	6,100,000
	Total - Substations	3,425,000
	Total - Automated Switches & SCADA	1,400,000
	Total - System Maintenance	5,450,000
	TOTAL - SYSTEM EXPANSION	**22,225,000**
	TOTAL - OTHER CAPITAL	**9,532,600**
	GRAND TOTAL	**31,757,600**

Response: 1. c)

Yes C/5/1 contains the "business cases" for all major 2008 System Expansion and Other Capital Projects. The CIS Capital Project is documented in SEC Interrogatory Responses #s 28 and 30. The capital projects that are not System Expansion/Other Capital are attached and are related to Non-System Requirements - Regulatory Driven Investments and Internally Driven Investments.

EHM PROJECT BUSINESS CASE	
INVESTMENT CATEGORY:	**Non-System Requirements – Regulatory Driven Investments**
INVESTMENT NAME:	**Wholesale Metering**
PROJECT NAME:	**Wholesale Metering**

Business Need:
All wholesale metering installations used for settlement in the IESO-administered market must be registered with the IESO in line with the IESO Market Rules Chapter 6, section 3.2. Secondary, the metering installation shall comply in accordance to Measurement Canada's Electricity & Gas Inspection Act. Specifically, all instrument transformers and meters must be approved by Measurement Canada. If any of the Instrument Transformers (IT) is not approved by Measurement Canada, the non-compliant IT must be replaced or approved at the earliest seal expiry date.

Investment Summary:
Under the IESO Market Rules, Enersource is responsible for the costs of installing and maintaining the metering installations. However, Enersource must contract the services of an IESO registered Meter Service Provider (MSP) such that only registered MSP are authorized to undertake the registration of meter installation for operation in the IESO wholesale electricity market. Enersource will purchase and install wholesale metering at the new Winston Transmission Station expected to be constructed Hydro One in the spring of 2009.

Wholesale metering installations expiring in 2008 and beyond that have Measurement Canada Instrument Transformer temporary permission instrument transformers (IT) expiring in the same year require corrective action to ensure compliancy with Measurement Canada. On June 10, 2004, Measurement Canada accepted Hydro One's proposed long-term corrective action plan to address the continued use of Instrument Transformers (IT) that have not been approved by Measurement Canada (non-approved IT). The following information outlines Measurement Canada's ruling on the IT temporary permission and the actions required by Metered Market Participants (MMPs) to ensure compliance with Measurement Canada.

For metering installations with an earliest meter seal expiry date between 2003 and 2005 that use non-approved ITs, temporary permission expires 6 years from the earliest meter seal expiry date. For metering installations with an earliest meter seal expiry date between 2006 and 2008, the temporary permission expires in the same year as the earliest meter seal expiry date. In all cases, the use of non-approved ITs must end by December 31st of the year temporary permission expires. For Enersource Hydro Mississauga in the 2008 rate year, three (3) wholesale metering installations will require to be fully upgraded as a result of expiry of Measurement Canada's temporary permission for continued use of non-approved Instrument Transformers.

Results:
To install new wholesale metering compliant with the IESO Market Rules and Measurement Canada at Winston TS at the most economical cost. Secondly, to upgrade the non-compliant wholesale meters as a result of the expiry of Measurement Canada's Temporary Permission to continue to use non-approved ITs in line with IESO Market Rules and Measurement Canada requirements.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008	2009	
Capital Costs funded by Board	145	3,000	
Capital Costs funded by Others			
Total Capital Costs	**145**	**3,000**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	Non-System Requirements – Regulatory Driven Investments

INVESTMENT NAME:	**Smart Metering**
PROJECT NAME:	**Smart Metering**

Business Need:

In order to foster a "conservation culture" in Ontario, the Ministry of Energy seeks to have Smart Meters commissioned throughout Ontario by the end of 2010. A Smart Meter records the energy consumed according to the time of day that it was consumed and is required to support the implementation of Time of Use ("TOU") commodity prices. Pursuant to O. Reg. 427/06, Enersource has commenced the mass deployment of Smart Meters to its residential and small commercial customers.

Investment Summary:

Enersource's Smart Metering System includes:

- an Advanced Metering Infrastructure ("AMI");
- interface with a Meter Data Management Repository ("MDM/R"); and
- TOU billing functionality enabled in the utility's Customer Information System ("CIS").

Enersource is responsible for installing, commissioning, operating and maintaining the AMI system. The AMI infrastructure includes the Smart Meter, regional collector computers that operate through a local area network and a controller computer. The AMI interfaces with the MDM/R once a day and uploads consumption information for all the customers. The MDM/R validates and, when necessary, estimates consumption data and prepares the data for billing purposes. The billing data is sent by the MDM/R to Enersource's CIS system and Enersource prepares the customer's bill.

In order to realize the benefits of the AMI systems, the following steps and actions must be taken:

- Preparation and distribution or release of customer and community communications;
- Plan and implement Project management (e.g., staff training, logistics, contract management)
- Procure the system;
- Install the system;

All steps must be planned and implemented with attention to quality and quality control (e.g., an audit of system security should be included in the testing step.)

Results:

During the 2008 Test Year, Enersource plans to install approximately 41,300 Smart Meters as follows:

- 36,000 residential Smart Meters; and
- 5,300 Smart Meters for small commercial and industrial customers where metering of demand is not required.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008	2009	2010
Capital Costs funded by Board	8,075	8,237	8,308
Capital Costs funded by Others			
Total Capital Costs	**8,075**	**8,237**	**8,308**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Expansion & Upgrades - Customer Driven Investments**
INVESTMENT NAME:	**Metering Equipment**
PROJECT NAME:	**Metering Equipment**

Business Need:

This investment is required to maintain the retail meter inventory to ensure accurate and dependable billing. Failure to maintain an adequate or properly functioning meter inventory could produce inaccurate billing which may result in customer disputes concerning sales and revenues. This investment does not include smart metering.

Investment Summary:

Under Enersource's smart metering plan, all residential and small general service customers that do not require demand metering will have a smart meter installed. The rest of Enersource's customers include approximately 4,400 general service commercial and industrial customers that require demand metering. The investment also includes costs to:

- upgrade existing metering (e.g., due to customer electrical service upgrades);
- to replace obsolete or damaged meters; and
- to convert from 2.5 element to 3 element metering.

The spending level in 2008 assumes that 560 meters, including hardware (e.g., current transformers, potential transformers along with other miscellaneous parts such as cable wires, test blocks and meters seals required to complete the installation) are included.

Results:

The funding for this investment will insure that there is adequate inventory of meters and metering equipment for prompt installation of new services or replacement of damaged metering equipment. Efficient and accurate meter installation and replacement ensures that all Measurement Canada and any other applicable regulatory requirements are upheld.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008	2009	
Capital Costs funded by Board	889	488	
Capital Costs funded by Others			
Total Capital Costs	**889**	**488**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**Information Technology**
PROJECT NAME:	**Information Technology**

Business Need:

The 2008 capital budget is required to replace and upgrade IT infrastructure to meet the needs of the business both present and future. Infrastructure includes desktop/notebook systems for over 200 users, application servers, storage, networking and datacenter equipment. The budget also allows for a 3% increase in employee count in 2008.

Investment Summary:

Desktop upgrades : $140,000

Users PCs are replaced every 3 years in order to reduce support costs and to provide adequate computing needs for the business applications ever increasing functionality processing demands. In 2008, 50 notebooks will be at the end of their lifecycle and will be replaced. There is also an allowance for additional units for new hires and new business requirements.

Server infrastructure upgrades: $365,000

As the requirement for additional systems and application functionality grows, so the hardware (servers) will need to be upgraded to meet the computing demands. In 2008, we will be upgrading the following systems;

- increasing the tape (storage) capacity of the corporate backup system
- replacing 4 obsolete servers with newer Blade units
- optimizing the use of hardware by investing in virtual servers (VMware) to run smaller applications
- increasing the memory and storage requirements of the Customer Information System (CIS) to allow for the implementation of smart meters.

Computer room upgrade : $90,000

Tests done in 2007 showed that the UPS is only capable of sustaining the power in the data center for 20 to 30 minutes. This is due to the steady increase in servers over the past few years and is not enough to allow for the orderly shutdown of the network to prevent hardware malfunction and data corruption. The battery farm in the UPS will be upgraded in 2008 to allow for a more acceptable uptime.

Application development : $125,000

It is anticipated that the new CIS system being developed will require minimal customization after "go live". This funding is to cover new user reports to be developed in addition to a bill re-verification system that will audit the daily billing process as is currently done on the existing system.

Results:

Improved efficiency, reliability and redundancy of all the business systems is achieved by this capital expenditure.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008	2009	2010
Capital Costs funded by Board	$720	$725	$655
Capital Costs funded by Others			
Total Capital Costs			

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**Grounds and Buildings**
PROJECT NAME:	**Grounds and Buildings**

Business Need:

Grounds and Buildings capital budget is used to provide major infrastructure replacements and new purchases of facility systems and or equipment, that is used in the day to day operations of the head office facility at 3240 Mavis Rd.

Investment Summary:

HVAC Upgrades: $600,000

To ensure that the building's major air systems are operating at optimum capacity, upgrades to existing systems are required. This year's major upgrades are in the Cooling Tower, as well as two large air handling units for the South Tower. Current units are past their life cycle and require replacement.

Control Room Upgrades: $175,000

Provide new consoles; upgrade seating, new monitoring equipment. These upgrades will provide a more modern updated and efficient control room for staff to function at optimum efficiencies.

Pole Yard and Parking Lot Upgrades: $200,000

These two line items will provide a safer storage area in the pole yard for transformers, poles, as well as pad mount units. The paving of the south parking lot will address heaving and cracked pavement issues and allow for more efficient plowing methods during winter months.

Electrical Panel Upgrades: $ 100,000

Funds will be used to provide for upgrading old and outdated panels that will meet ESA code guidelines and are more reliable as building staffing levels grow and new systems are required.

Environmental Issues: $300,000

Address issues related to old storage tanks buried in the yard, PCB containment, Stormceptor Installation.

Energy Efficiency Upgrade Program (continuation of 2007): $200,000

T8 lighting retrofits to remaining office floors and main garage. Water smart Shower Controls for the Men's change room

Interior Renovations: $200,000

Funds will be used to update carpet in worn areas of the facility with environmentally friendly carpet tile, refresh walls with new paint and wall covering in general staff areas.

Furniture Upgrades: $100,000

Update and install new workstations to accommodate anticipated staff growth in several areas of the Corporation

Structural Improvements to Main Building: $ 175,000

Funds will be spent on the upgrade of all curtain wall and structural systems on building exterior to address aging and bring up to current code standards

Security Systems/Hardware Upgrades: $50,000

Address security needs and expanding building staff with new security management software, visitor management system, and upgrade aging surveillance systems to current technology levels.

Garage Walls- Repainting: $ 50,000

Repaint all garage walls to clean up grease and grime. Will assist in reducing the dust in garage and improve the air quality.

Results:

The use of these funds allows the Grounds and Buildings Division continue to provide support to all departments within the Corporation, and provide a comfortable and safe work environment for all staff.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008	2009	2010
Capital Costs funded by Board	2,150	2,000	
Capital Costs funded by Others			
Total Capital Costs			

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**Engineering & Asset Systems**
PROJECT NAME:	**Engineering & Asset Systems**

Business Need:

The Engineering & Asset Systems capital budget is used to provide information technology tools to assist our personnel in managing our field assets throughout the life cycle. These tools include software and hardware for 170 people in Enersource Hydro Mississauga, including both office and field personnel. It is projected that the user community for these technologies will increase by 3% in 2008.

Investment Summary:

Upgrade Workstations, Plotters and Field Computers: $275,000

To ensure that all of our hardware is kept current, it is refurbished or replaced every three years. For 2008, 35 high-end workstations, 30 monitors and 3 servers are scheduled for replacement in order to bring this equipment up to current standards. An estimated 5 workstations are planned for new personnel. Our strategy to replace equipment every three years extends to field personnel as well. Twenty field lap-tops are scheduled for replacement with an additional 4 required for new personnel.

Engineering Analysis Software: $170,000

This line item combines a number of small projects and software acquisitions. Additional licenses of several of our Engineering software applications are required so that information and analysis capability can be made available to more of our internal and field personnel. We plan to upgrade one of the most heavily utilized field data collection modules. We intend to more fully utilize the corporate Engineering Document Management software application by implementing additional modules.

Integrated Operating Model (SCADA & AM/FM/GIS Integration: $1,100,000

By integrating these two key corporate systems, our goal is to streamline processes for Operations personnel. We intend to eliminate any remaining duplicate record-keeping processes, reduce manual paperwork and reporting in the field, and provide automatic reporting of reliability indices. Additionally, we aim to fully automate the tracking of customer interruption reporting, including providing a detailed audit trail. This line item includes all hardware, software and training.

Results:

The use of IT systems supported by this budget assists Enersource to improve efficiency and reliability, reduce costs and ensure the safety of our crews and the public.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2008	2009	2010
Capital Costs funded by Board	$1,545	$1,495	$1,540
Capital Costs funded by Others			
Total Capital Costs			

Response: 1. d)

Total capital expenditure for Overhead Distribution Upgrades for 2008 is $2.6M. This is the sum of the following overhead capital expenditures(C/5/1):

- **Wood and concrete pole replacement program :$824**
- **Overhead switch & insulator equipment replacement prpgram:$464**
- **Overhead rebuilds: $926**
- **Feeder overhauls: $386**
- **Total: $2,600**

The Primary Distribution Equipment Replacement, $600 (C/5/1) included under Overhead Distribution Upgrades is required as a result of the feeder overhaul program (an overhead program), however the components used (fault indicators, arresters, elbows, inserts) are underground components and should be included in the calculation of total Underground Distribution Maintenance.

Question #2
-Reference: i) Staff #1

Preamble:

The main reason for the land purchase ($2.5) appears to be the need for additional parking. The current site provides parking for 291 employees and Enersource Hydro's total employee base as of July 2007 is 323 (including vacancies) and is expected to be at this same level in July 2008 (Staff #3).

(a) Does Enersource provide parking to each employee as part of their employment agreement? Do all employees drive to work? Were other options (e.g., incentives to use public transit) considered that might have a lower overall cost?

Response: 2. a)

Enersource is unable to provide a written response due to limited time and resources.

Question #3
-Reference: i) VECC #15

(a) Please provide details as to how the low/high values for the individual cost items were determined.

Response: 3. a)

The high/low values for the individual cost items were determined through a discussion with Enersource Corporation's Treasurer based on his knowledge of typical and extreme cash requirements of the business.

II. Operating Revenues

Question #4
-Reference: i) VECC #11

(a) In part (b) of this question, the request had been to get Table 1 on page 5 of B/3/2 in a weather normalized format. The purpose was to see how the total energy use has been growing historically on a weather normalized basis from 1999 to 2006. The same was the case for part (d) of the question – which dealt with peak demand as opposed to energy.

Please provide the weather normalized values and comment on the reasons for any changes between historical average increases and the forecasted increases for 2007 and 2008.

Response: 4. a)

Weather Corrected Consumption Energy (MWh) from 1999-2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Jan	606,536	632,324	657,965	679,473	698,462	704,065	708,305	711,284	720,267	743,340
Feb	545,959	590,826	586,496	607,992	628,694	657,097	635,043	640,986	652,353	689,192
Mar	579,987	602,215	625,154	638,560	660,134	677,347	679,773	688,284	688,433	696,623
Apr	524,160	539,457	560,575	590,917	604,123	616,539	616,519	611,704	626,800	648,598
May	529,427	559,734	580,656	605,904	616,952	622,928	630,091	640,101	654,424	658,467
Jun	572,299	589,098	609,339	627,324	638,882	652,357	671,881	671,914	675,982	679,732
Jul	619,945	647,989	662,802	703,735	707,202	711,214	727,505	734,666	742,332	753,380
Aug	608,828	635,220	659,988	684,396	683,386	693,365	715,748	718,763	723,439	725,365
Sep	547,666	568,356	584,047	611,588	612,468	642,474	639,131	635,322	645,955	659,036
Oct	548,861	576,146	600,165	620,559	623,829	636,362	640,827	645,952	665,464	672,357
Nov	569,948	589,548	611,197	629,365	635,281	650,927	653,676	656,538	674,176	674,504
Dec	617,121	626,671	644,378	668,534	681,827	692,021	689,635	689,818	711,355	724,195
Total	**6,870,737**	**7,157,584**	**7,382,762**	**7,668,347**	**7,791,240**	**7,956,696**	**8,008,135**	**8,045,331**	**8,180,980**	**8,324,789**
Growth	**-**	**4.17%**	**3.15%**	**3.87%**	**1.60%**	**2.12%**	**0.65%**	**0.46%**	**1.69%**	**1.76%**

N.B.: May 2007-Dec2008 Load Forecast (Normal Weather)

Weather Corrected Peak Demand (MW) from 1999-2006

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Jan	1,029	1,079	1,116	1,148	1,154	1,155	1,201	1,214	1,268	1,422
Feb	1,000	1,036	1,067	1,105	1,125	1,130	1,159	1,177	1,183	1,409
Mar	960	1,003	1,025	1,056	1,073	1,091	1,120	1,130	1,132	1,360
Apr	951	975	1,002	1,045	1,052	1,063	1,086	1,096	1,111	1,284
May	972	1,002	1,058	1,071	1,101	1,097	1,083	1,127	1,293	1,312
Jun	1,091	1,227	1,278	1,297	1,296	1,195	1,345	1,376	1,436	1,456

Jul	**1,130**	**1,274**	**1,296**	**1,340**	**1,357**	**1,296**	**1,392**	**1,422**	**1,512**	**1,531**
Aug	1,103	1,177	1,232	1,258	1,294	1,283	1,347	1,331	1,488	1,507
Sep	999	1,095	1,123	1,144	1,145	1,166	1,198	1,204	1,370	1,390
Oct	957	1,011	1,012	1,044	1,095	1,094	1,107	1,095	1,239	1,259
Nov	1,012	1,039	1,083	1,105	1,118	1,127	1,146	1,144	1,297	1,316
Dec	1,058	1,098	1,128	1,153	1,169	1,196	1,187	1,205	1,372	1,391
Peak	**1,130**	**1,274**	**1,296**	**1,340**	**1,357**	**1,296**	**1,392**	**1,422**	**1,512**	**1,531**
Growth	**-**	**12.71%**	**1.75%**	**3.38%**	**1.30%**	**-4.52%**	**7.47%**	**2.12%**	**6.33%**	**1.26%**

N.B.: May 2007-Dec2008 Load Forecast (Normal Weather)

Year	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Population	616,587	632,384	647,105	660,677	673,047	684,182	694,068	702,714	710,146	716,414
Population Growth	**2.80%**	**2.56%**	**2.33%**	**2.10%**	**1.87%**	**1.65%**	**1.44%**	**1.25%**	**1.06%**	**0.88%**
Housing	188,775	193,700	198,525	203,206	207,723	212,044	216,155	220,016	223,604	226,890
Housing Growth	**2.73%**	**2.61%**	**2.49%**	**2.36%**	**2.22%**	**2.08%**	**1.94%**	**1.79%**	**1.63%**	**1.47%**
Employment	364,831	375,229	386,143	397,239	408,266	418,987	429,246	438,857	447,718	455,741
Employment Growth	**2.70%**	**2.85%**	**2.91%**	**2.87%**	**2.78%**	**2.63%**	**2.45%**	**2.24%**	**2.02%**	**1.79%**

N.B.: 2007 and 2008 figures are forecast.

For energy consumptions, the average weather normalized annual growth experienced from 1999 to 2006 was 2.29%. The forecasted energy consumption growth for 2007 is 1.69% relative to the weather corrected 2006 annual consumption. The 2007 energy consumption forecast includes weather corrected data from January to April 2007 and load forecasted data based on normal weather from May 2007 to December 2007. The forecasted energy consumption growth fro 2008 is 1.76% relative to the 2007 consumption based on weather corrected data up to April and normal weather scenario forecast from May to December 2007.

Upon applying the expected conservation energy savings of 39,054 MWh for 2007 and 57,678 MWh for 2008 to the load forecast, the forecasted normal weather annual growth relative to weather corrected historical data is 1.20% for 2007 and 1.54% for 2008.

For peak demand, the average weather normalized annual growth experienced from 1999 to 2006 was 3.46%. Under the normal weather scenario, the expected peak demand forecast yields an annual growth rate of 6.33% for 2007 and 1.26% for 2008.

To explain the decreasing growth rate of energy consumption, econometric driver data with annual growth rates is provided. With dwindling availability of land supply, Mississauga is transitioning from a growing

municipality based on expansion to a mature city with growth from intensification and redevelopment.

From 1999 to 2006, the population of Mississauga grew by approximately 86,000 people at an average rate of 1.89%. From 2004 to 2006, the population grew by approximately 18,500 people at an average rate 1.35%. The forecasted population growth for 2007 and 2008 is 1.06% and 0.88% respectively.

From 1999 to 2006, the housing stock of Mississauga grew approximately 31,200 units at an average rate of 2.2%. From 2004 to 2006, the housing stock grew by approximately 8,000 units at average rate of 1.9% per year. The forecasted housing unit growth for 2007 and 2008 is 1.63% and 1.47%. Future housing stock is expected in more dense structure as expected with growth based on intensification and redevelopment.

From 1999 to 2006, the employment of Mississauga grew by approximately 74,000 jobs at an average rate of 2.7%. From 2004 to 2006, the employment grew by approximately 19,900 jobs at average rate of 2.3% per year. With an aging population, demand for service related employment is expected to continue into 2007 and 2008. Taking into account Mississauga's will educated population and close proximity to 6 major highways, office related employment is expected to continue growth in 2007 and 2008. Growth of office and population service related employment is forecasted to be greater than the losses of land related employment (manufacturing, warehousing, etc.) such that employment growth is expected to be 2.02% and 1.79% for 2007 and 2008, respectively.

Question #5
-Reference: i) Staff #16

This question had asked for historical data by class on a weather normalized basis. However, the response does not provide "weather normalized" sales by customer class – only actual sales. Again the purpose was to see how the forecast growth rates for the various classes compared with the historical ones – when the year over year effect of weather is removed.

Please provide the weather normalized values by class and comment on the reasons for any changes between historical average increases and the forecasted increases for 2007 and 2008.

Response: 5.

Given the nature and complexity of allocating weather normalized values by customer class EHM is unable to provide the requested information. Please refer to response #4 for comparisons of weather normalized values from 1999 to 2008 and the reason for changes between historical average increases and the forecasted increases.

Please note that EHM's budget process is to use forecasted energy purchases in kWh per Short Term Load Forecast Exhibit B / Schedule 3 / Tab 2 which are then allocated to each customer class based on the three year actual average for each respective customer class. Energy related to residential, small commercial and general service class less than 50 kW are then calculated. For the general service classes greater than 50kW, large users, and street lighting a three year actual load factor are used to convert the kWh to KW for billing demand. The resultant forecast was adjusted for projected CDM programs in the 2008 Test Year.

Question #6
-Reference: i) Staff #20 and VECC #12

(a) Looking for more details as to how the values in Schedule B/2/2,1 (i.e., CDM adjustments) were determined.

Response: 6. a)

The values provided at Exhibit B/ Schedule 2/Tab 2.1 were determined as follows:

- **The results attributable to Enersource's Third Tranche and Second Generation Conservation and Demand Management programs by customer class were estimated by its CDM group;**
- **It was assumed that these results would be attained in the 2008 Test Year;**
- **The annual results were allocated to specific months assuming that lower results would be generated in the earlier months of the period and that greater results would be generated in the later months of the period;**

In hindsight the assumption that the past results would be attained in the 2008 Test Year may be unduly conservative; according to Ontario's Chief Conservation Officer and as documented in his annual report past CDM results have resulted in a x.x% reduction in energy and in demand.

III. Operating Costs

Question #7
-Reference: i) VECC #19 and Staff #31

(a) The objective behind the VECC IR was to identify the external drivers leading to the increase in staff and manpower costs. Is it possible to show the number of additional staff by function (i.e., the various areas set out in D/2/2) and discuss, for each function, what are the external factors that lead to the need for additional manpower.

Response: 7. a)

Staffing Changes and reason

Rates	Position Name		2005-2007	2007-2008	2008	Reason for position
No	Billing Analyst	Customer Service Admin	1			This position assumes the responsibility of reporting and analysis requirements for Enersource Hydro Customer Care and Billing Operations Division.
No	Billing Supervisor	Customer Service Admin			1	A new Billing Supervisor position has been authorized to help the Manager, Billing Operations deal with:• the increased administrative complexity expected as a result of Smart Metering, billing at Time of Use rates, Standard Offer Program;
No	Customer Service Supervisor	Customer Service Admin		1		Increased demands and aging workforce.
No	Billing Quality Analyst	Settlements		1		This person is responsible for ensuring and validating metering and settlement system configurations, meter data and meter billing for MIST (Metered Inside Settlement Timeframe) customers. Responsibilities include auditing, validating and reporting results
No	Office Services Clerk	Customer Accounts	1			Responsibilities: • Assign postage to all outgoing corporate mail and deliver the mail daily to the Post Office • Co-ordinate the equipment maintenance requirements and operate the Mail Inserter & Postage Machines for corporate outgoing mail and bills.
No	System Admin	Customer Accounts			1	The administrative duties related to Kubra services will grow to encompass user security, reporting, payment tracking and an e-bill bill inserts marketing segment with the upgrade early 2008. SharePoint will be our new document management software which will require an administrator.

No	Meter Technician Apprentice	Metering	1			Required to meet the quality assurance targets for Enersource.
No	Apprentice	Metering			1	The new apprentice is required to meet the mandates of the OEB for our Smart Meter initiative, which would include the installation of network communication collector meters; smart meters for C/I customers and our IMS projects.
No	Middleware Tech	Information systems			1	Managing the new "middleware" framework that will be implemented later this year.
No	New Network Specialist	Information systems			1	Additional position required due to increased demands and system complexity.
No	New Data Base Analyst	Information systems			1	Database Administrator for managing the new CC&B system.
No	New - IOM programmer	Information systems			1	The IOM System will be installed in 2008 and will require a Senior Programmer/Analyst for its support and maintenance. This is a new system, so we do not currently have anyone in this position.
No	Operating Model Engineer	Information systems	1			Ensure the availability and integrity of the operating model, complex data set compile from our AM.FM/GIS and scada systems and utilized by the system control operator to operate the distribution system.
No	New Standards Clerk	Admin		1		ESA Regulation 22/04 has come into effect and significantly increased the due diligence requirements for Enersource. The bulk of the compliance work is in the standards group. It also presented an opportunity to sell Standards and now upgrades to other LDCs.
No	Design Tech	System Planning			1	The Design Tech position is new to allow for the training of a new person to fill an upcoming retirement. Training of this nature is highly specialized and takes several years. The position is also required as a result of increased capital expenditures.
No	Grid planner/analyst	Corporate Records	1			The Grid Planner position was proposed as a new position that would perform the short term planning of the switching activities on the power grid. Typically, a system operator would be viewed as going into this position, however, with retirement and new a
No	Apprentice	Control System	1			New apprentices required to move from an 8 person rotation to a nine person rotation. The second position is to prepare an apprentice for the upcoming planned retirement of existing staff.
No	Apprentice	Control System			1	New apprentices required to move from an 8 person rotation to a nine person rotation. The second position is to prepare an apprentice for the upcoming planned retirement of existing staff.
No	Mapping engineer	Corporate Records			1	The Systems & Mapping Engineer is a new position necessitated by the implementation of the IOM System, and support the GIS middleware software and manages aspects of import/export workflow.

No	Apprentice	Substation Operations	1			The Apprenticeship Program is intended to provide additional line staff resources to replace employees that have been lost through attrition.
No	Apprentice	Substation Operations			1	The Apprenticeship Program is intended to provide additional line staff resources to replace employees that have been lost through attrition.
No	Materials Planner	System Planning	1			This position is responsible for preparing, maintaining, and coordinating construction schedules for capital, subdivision, industrial/ commercial and some maintenance service orders in a multiple project environment in the E&O division of Enersource.
No	Weekend Shift TTK	U/G Maint. & Repairs	1			This is an additional night permanent night shift crew to allow full 7 day a week 24 hour trouble truck coverage, which will improve response time to outage on weekend nights and help maintain our system reliability.
No	Weekend Shift TTK	O/H Maint. & Repairs	1			This is an additional night permanent night shift crew to allow full 7 day a week 24 hour trouble truck coverage, which will improve response time to outage on weekend nights and help maintain our system reliability. It will also ensure that we are able
No	Apprentice	U/G Maint. & Repairs			1	The Apprenticeship Program is intended to provide additional staff resources to replace employees that have been lost through attrition.
No	Apprentice	Tree Trimming		1		The Apprenticeship Program is intended to provide additional staff resources to replace employees that have been lost through attrition.
No	Apprentice	Tree Trimming		1		The Apprenticeship Program is intended to provide additional line staff resources to replace employees that have been lost through attrition.
No	Clerk	Industry/Commercial inspections	1			This position was budgeted to meet increasing requirements to process time charges from numerous Dept's.
No	Storekeeper	Stores	1			New projects. Also tool recording safety history, with regards to maintenance and repair. Safety reporting, monitoring gloves and safety wear.
No	ESA Compliance	Stores			1	Dealing with Ministry of Environment with regards to transformer history monitoring.
			12	5	13	

Question #8
-Reference: i) VECC #22

(a) The question was seeking to determine whether Enersource charges any of its indirect costs (e.g. General Administration costs) to capital programs and, ultimately, rate base. The referenced part of the Application does not appear to address this issue. What costs, if any, does Enersource capitalize to construction projects besides the direct costs incurred for the project itself? Is there a policy addressing this and, if so, provide?

(b) The response suggests overheads are capitalized (i.e. included) for customer projects. Please provide more details on what is meant by "customer projects" and precisely what types of costs are included. Is this the Administration Burden rate discussed on page 5 of D/1/11?

Response: 8. a)

Apart from the direct costs incurred to the projects itself, Enersource capitalizes the labour and material burdens charged to the projects. The labour burden is applied to direct labour costs recorded through the work order system so that indirect labour costs associated with managers, construction supervisors and various non-union staff (management level employees who do not complete out timesheets and are involved in the subject project) are appropriately tracked and assigned. Material burden covers the indirect costs incurred from procuring inventory, material handling and storage of inventories. The application of labour and material burden results in a reduction of Enersource's operating expenses that are recovered through distribution rates.

Response: 8. b)

Administration burden is applied only to recoverable work (e.g. Inspection/energization work; consumer projects) only and covers indirect labour costs associated with collections, accounting (costing and billing of work orders) and operations division overhead. Administration burden is a reduction to expense.

Question #9
-Reference: i) VECC #23

(a) What is the reason for the increase in Retail Transaction Hub costs?

(b) Is it offset by increased revenues from retailers?

(c) If not, why isn't Enersource applying for an increase in its Retailer service charges?

Response: 9.

a) The 2006 $130k represents all the expenses related to the retail transaction hub less revenue from retailers. The 2007 and 2008 represent EHM's forecasts of revenue from retailers which exclude the costs associated with the retail transaction hub. In the 2008 Rate Application EHM has assumed all other expenses in 2007 and 2008 pertaining to the retail transaction hub would be offset by other revenue (revenue from retailers). Retail transaction hub costs along with the associated revenue from retailers are maintained in RCVA Retail and STR accounts 1518 and 1548. EHM forecasts the costs over recovery for 2007 and 2008 will decrease from 2006.

b) See response to a above.

c) See response to a above.

Question #10
-Reference: VECC #24 and Staff #51 & 52

a) Please reconcile the monthly charges reported in reference (ii) for each customer class with the monthly charges used in reference (iii) to determine revenues at existing rates (e.g., the residential monthly services charges do not match).

b) Does Enersource have any other standby customers other than Brittania and GTAA? If so, where is the associated standby charge revenue accounted for?

c) Please describe further the new payment mechanisms that Enersource has recently introduced (reference (iv)).

Response: 10. a)

(a) The responses to Staff #51 and #52 should be amended to refer only to Staff #49. The spreadsheets showing the details of the SSM and LRAM calculations are attached to Staff #49. There are no separate spreadsheets specifically for Staff # 51 and 52.

All assumptions made for CDM calculations reflect and are supported by the OEB's TRC Guide.

Question #11
-Reference: VECC #9 and SEC #16

(a) The VECC IR asked if there was any mark-up for overheads included in the charges Enersource made to affiliates under the Service Agreements. The response does not address this issue. Please indicate whether any administration burdens are included in the costs allocated to affiliates or whether just the actual lines costs for IT and Facilities were allocated.

Response: 11. a)

The Return on Asset is an allocation that is marked up by the allowable Cost of Capital as provided by the OEB. Enersource Hydro does not include administration burdens in the costs allocated to affiliates. IT and Facilities costs are based on headcount and actual expenses.

IV. Deferral and Variance Accounts

Question #12
-Reference: Staff #44 and #45 b

(a) Please reconcile the LV Charge balance reported in Staff #44 ($221,698) with the value reported at G/2/3 ($252.9 k).

(b) Please explain using the values from the attachment to Staff #44 how the RSVA – Power amount of $6,249,678 owing to customers was determined.

Response: 12. a)

Reference: Staff #44 and #45 b

The LV Charge balance reported in the Board Staff Interrogatory #44 of ($221,698) was the balance as at December 31, 2006. Enersource is an embedded distributor of Hydro One's low voltage system and seeks to claim an estimated recovery of $252,886 in low voltage charges for the 2008 rate year as reported in G/2/3. The estimated amount for recovery is based on The OEB Decision and Order issued to Enersource Hydro Mississauga on April 12, 2006 to be effective on May 1, 2006.

Response: 12. b)

Reference: Staff #44 and #45 b

In the 2008 Test Year Rate Application, Enersource is proposing to clear the balance in Account 1588 – RSVA Power excluding Global Adjustment as at December 31, 2006 which is $(6,249,678). The balance in Board Staff Interrogatory response #44 requested to include Global Adjustment. The balances as at December 31, 2006 for Account 1588 RSVA Power and RSVA Sub-account Global Adjustment is shown below and agrees to Board Staff Interrogatory Response #44:

Account 1588	Balance as at December 31, 2006
RSVA Power	($6,249,678)
RSVA Sub-Account Global Adjustment	$6,527,406
	$277,728

The determination of the $6,249,678 is shown in the following table:

Enersource Hydro Mississauga
RSVA 1588 Power Excluding Global Adjustment

2005	**Opening Balance**	**Transactions/Interest**	**Amounts transferred to 1590 (Note)**	**Opening Balance**
1588 Power	(2,850,219)	(1,937,015)	-	(4,787,234)
1588 Power Carrying Charge	(115,492)	(259,322)	-	(374,814)
	(2,965,711)	**(2,196,337)**	**-**	**(5,162,048)**
2006				
1588 Power	(4,787,234)	(3,645,199)	2,850,219	(5,582,214)
1588 Power Carrying Charge	(374,814)	(408,142)	115,492	(667,464)
	(5,162,048)	**(4,053,341)**	**2,965,711**	**(6,249,678)**

Note - Amount was transferred to 1590 per the OEB's Motion to Review and Vary Decision (RP-2005-0020/EB-2005-0360) of October 3, 2006.

V. Cost Allocation

Question #13
-Reference: Staff 64 b)

(a) Please describe more fully the issue regarding the treatment of transformer allowance credits and its impact on the observed revenue to cost ratios presented in the Informational Filings.

Response: 13. a)

Enersource is aware that some distributors have concluded that the revenue to cost ratio computed for the Large User customer class relies on revenues not reduced for the Transformer Allowance. Enersource has computed its Large User class' after Transformer Allowance revenue to cost ratio to be approximately 121%. The calculation is provided below.

TECHNICAL CONFERENCE QUESTIONS FOR ENERSOURCE

EB-2007-0706

FROM THE CONSUMERS COUNCIL OF CANADA

CCC – 2

Enersource has held the level of late payment revenue at 2007 levels for 2008. What is the current forecast for 2007 given actuals to date?

Response:

The current forecast for 2007 should be reduced in light of October YTD actual for late payment revenue which is $292k.

CCC – 3

If Enersource has no knowledge of the accuracy of the City of Mississauga's planning forecast why is Enersource relying on it for its load forecast? CCC would like some further detail regarding how the load forecast was developed.

Response:

To be clear, Enersource's load forecasting methodology does not forecast the number of customers. The evidence reference provided notes that Enersource relies, in combination with past experience of customer growth together with the City of Mississauga's economic planning forecast issued by the City's Planning and Building Department to forecast the number of customers.

The load forecasting methodology utilizes a top down approach based on energy purchases from the wholesale electricity market. The forecasting system adapted uses equations based on drivers such as weather effects, econometric data and calendar variables. Using regression techniques, the model quantifies the relationship between these drivers for energy consumption output and for energy peak demand output. Since the forecast is based on a top down approach, the process does not forecast the number of customers.

The City of Mississauga's Planning and Building department utilizes the population, employment and housing forecasts to develop Mississauga's 'Official Plan' which outlines policies for:

- **the location and type of housing, employment areas, parks, schools and hospitals**
- **needed services such as public transit, roads, storm sewers, fire protection**
- **protection of natural areas and ecosystems**

Based on general and specific policies for each planning district, the City of Mississauga applies these policies to zoning and permit allocation, thus controlling the building and development in the City.

The actual and forecasted economic drivers for the City of Mississauga used for Enersource's Short Term Load Forecast can be found to VECC question #11 response attachment "Economic Drivers used for Load Forecast". The development and application the econometric data is explained in section 4.0 and 5.0 of the "Short Term Load Forecast Report" in Exhibit B, Schedule 3, Tab 2 and also in section 3 and 4 of the "EHM Demand Forecast Report" in Exhibit B, Schedule 4, Tab 3.

CCC - 5

CCC would like a more detailed explanation as to how the new sub-metering regulation impacts Enersource's load forecast for 2008.

Response:

The regulations to facilitate the voluntary, should the condominium board of directors wish to proceed, installation of smart meters in condominiums is accounted in the 2008 load forecast for both new and retrofit installations.

In regard to retrofitting condominium units with smart metering to permit individual suite metering, the installation of the metering system would be completed on existing condominium building which has electricity already supplied and metered by Enersource. Thus, the historical usage and peak demand impact is already included in load forecast model. Conservation savings due to individual suite smart metering is unknown at this time.

New condominium unit growth is included in the City of Mississauga's econometric housing unit data. The actual and forecasted economic drivers for the City of Mississauga used for Enersource's Short Term Load Forecast can be found to VECC question #11 response attachment "Economic Drivers used for Load Forecast".

CCC - 10

Enesource had a Board approved forecast for software of $4.7 million, but only spent $$1.04 million. Please explain the reason for this variance.

Response:

The variance was mainly cause by a delay in CIS software spending.

CCC - 11

Enersource did not provide the forecast and actual energy and demand per customer for each class as requested in the question. Please provide this information. How, specifically did Enersource prepare the energy and demand forecast for each class for 2008?

Response:

Enersource first estimated the average residential consumption based on 2001 data and adjusted the level downward in 2006 to reflect the cumulative effect of Conservation and Demand Management initiatives. Please be aware that this data is used only when performing the Economic Evaluation required by the Distribution System Code. Listed below is the average residential consumption from 2004-2006.

Average Consumption	Year
791	2004
867	2005
803	2006

CCC - 16

Please provide all assumptions used to develop the $270,000 legal and consulting regulatory costs. Are these costs for this 2008 application only? If not, please provide the detailed elements.

Response:

Enersource's 2008 budgeted regulatory costs assumed that its 2008 rates application would be subject to greater scrutiny and would require more support than its 2006 EDR application. Enersource assumed that legal and intervenors would double. Enersource also assumed this amount would be required on an on-going basis for consulting services and external legal advice on other regulatory matters.

Board Staff – 6

Please provide a detailed explanation for the almost $5 million increase in computer equipment from 2006-2007.

Response:

The increase is mainly due to the new CIS billing software.

AMPCO Technical Conference Questions

Issue 1 ¬ Rate Base

AMPCO Question # 1
-Reference: Exhibit C/Schedule4/Tab 1 (Capacity Report)
Exhibit C/Schedule 5/Tab 1 (Business Cases)

Section 4.2 of the system capacity report notes that 25MW of additional load is will be introduced to serve the expansion of the Lakeview Water and Waste Water Treatment Plant and Other Water Pumping Stations. This section goes on to say" There will be no capacity expansion required in the 27.6kV South to meet this new load requirement"

In the Business Cases, the following projects all cite the expansion of these plants as the first driver for justifying expansion of system capacity:

Lakeshore Road – Hurontario Street to Cawthra Road
Lakeshore Road – Hurontario Street to Dryden Gate
Royal Windsor Dr – South on Southdown Road to Avonhead
Winston Churchill Blvd – Royal Windsor Drive to Lakeshore Rd, then east to Avonhead Road

Please explain the apparent discrepancy between the system capacity statement and the project justifications.

Response: 1.
Enersource is unable to provide a written response due to limited time and resources.

AMPCO Question # 2

The total cost estimated of the projects discussed in Question # 1 appears to be over $5M, with no capital contributions being required. Please explain.

Response: 2.

Enersource is unable to provide a written response due to limited time and resources.

Issue 3 – Operating Costs

AMPCO Question # 3
-Reference: Response to Board Staff IR #28

For the purposes of corporate cost allocation, EC's invoice to EHM for HR services is allocated on head count. Please provide the corresponding corporate cost allocation if the allocator was total compensation instead of head count.

Response: 3.
Enersource is unable to provide a written response due to limited time and resources.

Issue 5 – Cost of Capital

AMPCO Question # 4
-Reference: A12/T4 p. 2, VECC Question #7

Interest expense is projected to grow from $18.6 million in 2006 to $19.5 million in 2008 although the actual debt of the utility is not forecast to change over the period. Please confirm that the basis for the forecasted rise in interest cost in 2008 is driven by the change in rate base and that all deemed debt is calculated for revenue requirement purposes at the rate associated with historic debt. Please indicate the applicant's plan to finance the gap between deemed and actual debt.

Response: 4.
Enersource is unable to provide a written response due to limited time and resources.

AMPCO Question # 5
-Reference: E2/T1 and Response to Board Staff #58

In 2008, EHM is proposing a deemed debt principle of $303.242 million with an actual debt outstanding of $290 million at a coupon rate well above current short and medium corporate debt rates. Please explain why no lower cost short term or medium term debt is planned for 2008.

Response: 5.

Enersource is unable to provide a written response due to limited time and resources.

AMPCO Question # 6
-Reference: E1/T1 p. 3.

With respect to the BPC¬Enersource bond series issued in 2001 with a principle of $290,000,000 and a coupon rate of 6.29% and a claimed effective cost of 6.44%, please indicate:

a) the maturity or maturities,
b) early termination provisions,
c) any plans the applicant has to exercise exit provisions,
d) the premium, if any, at issuance.

Response: 6.
Enersource is unable to provide a written response due to limited time and resources.