Technical Meeting to Present Recalculated 2018 Loss Factors Determined Under Loss Factor Rule

John Martin, Senior Tariff and Special Projects Advisor

April 27, 2018 — Calgary, Alberta

Public

Disclaimer

- The information contained in this presentation is for information purposes only. While the AESO strives to make the information contained in this presentation as timely and accurate as possible, the AESO makes no claims, promises, or guarantees about the accuracy, completeness, or adequacy of the information contained in this presentation, and expressly disclaims liability for errors or omissions. As such, any reliance placed on the information contained herein is at the reader's sole risk.

Topics

- Summary of loss factors and related information posted on the AESO website on March 22
- Changes between April 24 and March 22 posting of 2018 loss factors
- Loss factor results, including exclusion rates and causes
- Shift factor results
- Comparisons of 2018 loss factors with 2017 loss factors
- Summary of base case development process
- Walk-through of hourly loss factor calculation
- Schedule for future loss factor work

Please ask questions during presentation

AESO published recalculated 2018 loss factors on April 24, 2018

- 2018 loss factors effective January 1, 2018
- Hourly merit order data for 2018 loss factors
- Sample of hourly load data for 2018 loss factors
- Process for requesting access to system topologies
- Procedure to determine transmission system losses for loss factor calculations
  - No change from 2017 procedure
- Software and scripts used to calculate hourly raw loss factors
- Workbook showing calculations for 2018 loss factors
- 2018 average loss factor for the transmission system is 3.61%
  - 2017 average loss factor was 3.60%

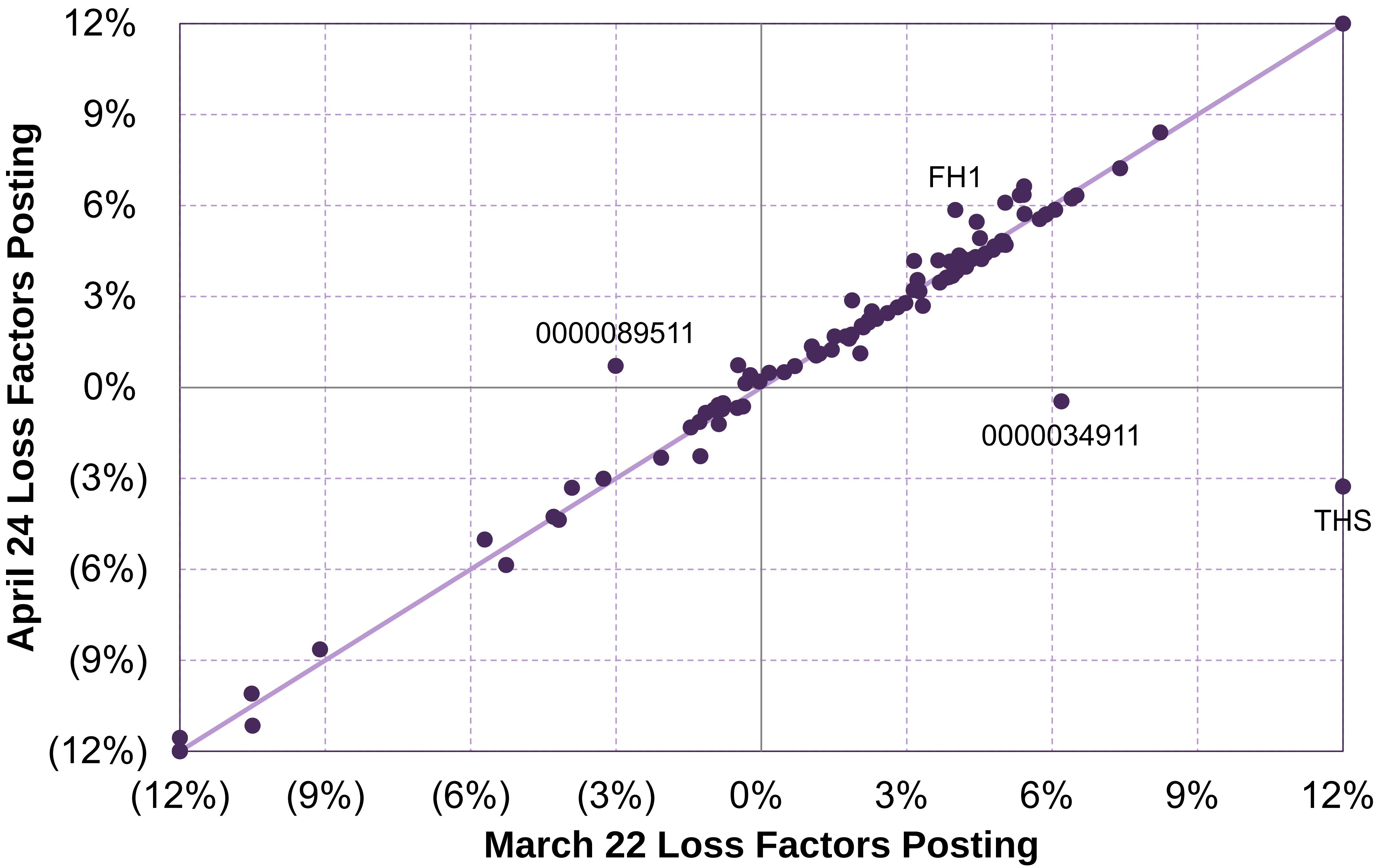
Data inconsistencies were corrected in April 24 posting

- Mid-2017 contract change for Medicine Hat had been implemented as a generator capacity reduction in merit order data in March 22 posting
  - Capacity in merit order has been reverted to correct levels
  - Merit order capacity increased from average of 77 MW in March 22 posting to average of 189 MW in April 24 posting
- Fort Hills load data had not been reduced in conjunction with the addition of Fort Hills generating capacity, resulting in Fort Hills remaining a net load in the March 22 posting
  - Fort Hills load has been corrected
  - Fort Hills has net-to-grid generation volumes of 45 MW in April 24 posting

Data inconsistencies were corrected in April 24 posting (cont'd)

- Some revisions to voltage settings were implemented in base cases to improve the number of successful solutions

April 24 loss factors are similar to March 22 loss factors except for very small generators



Unsolvable hours were reduced in April 24 posting

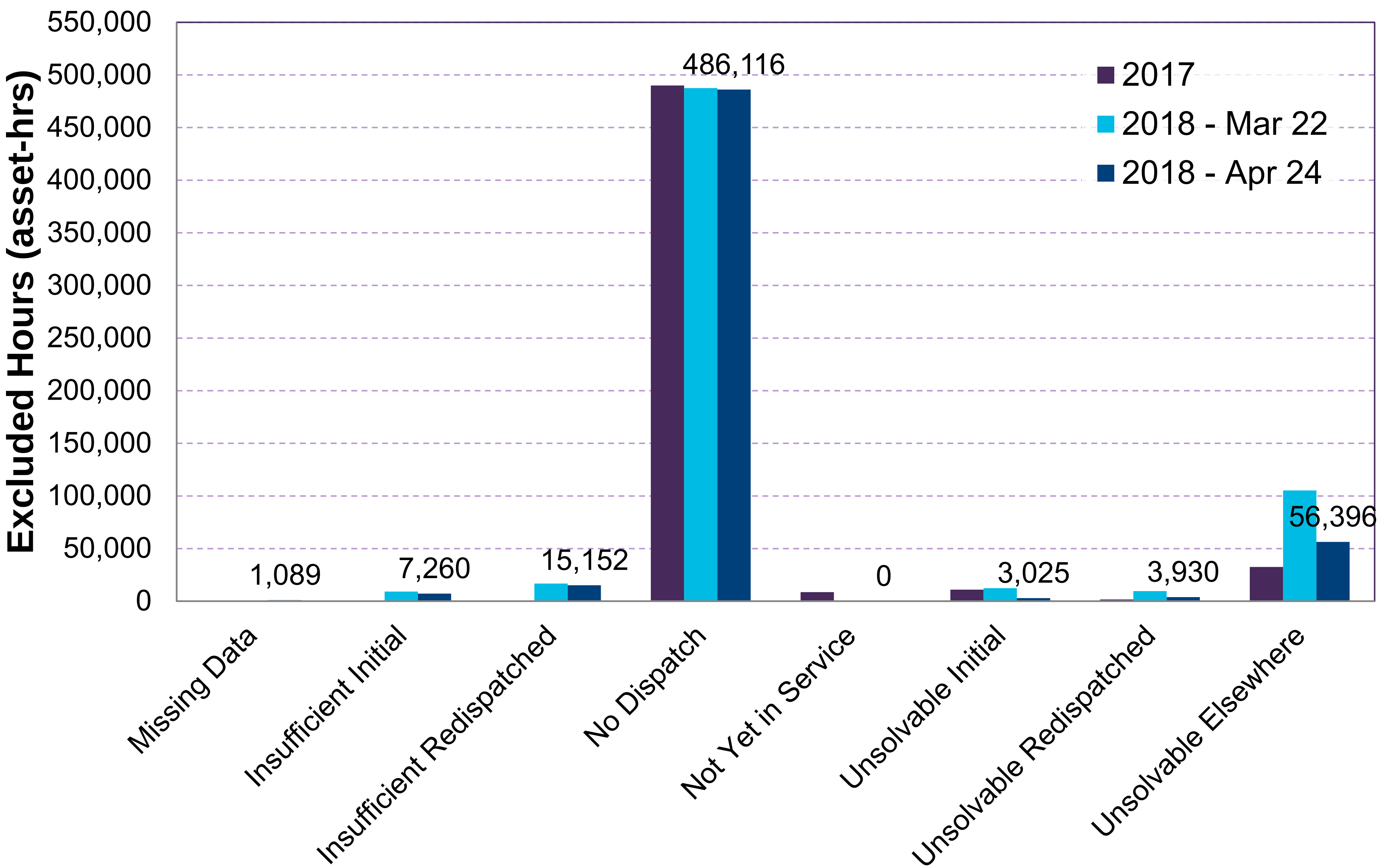
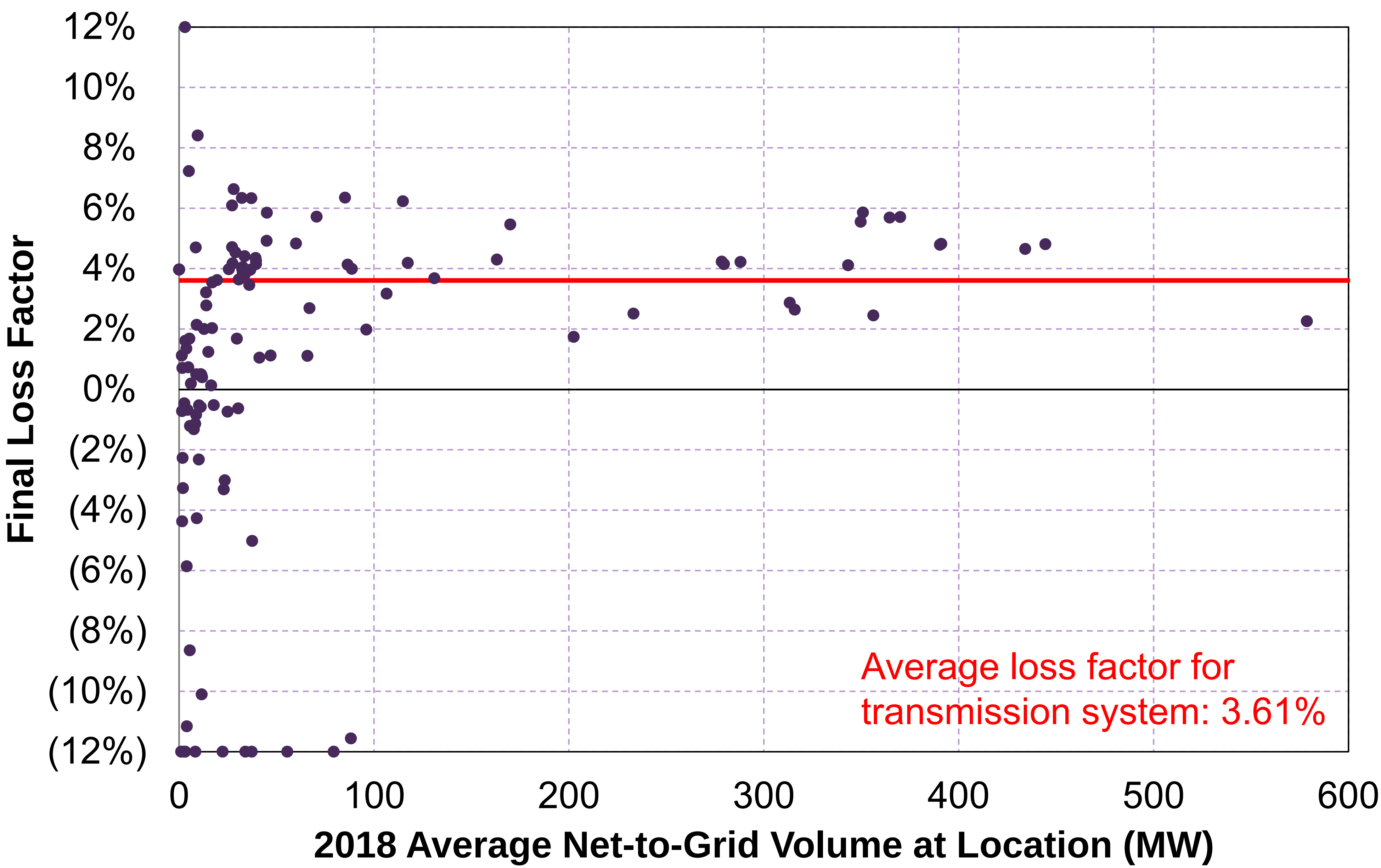


Chart legend corrected to Mar 22 (from May 22)

Final loss factors continue to show greater dispersion for smaller net-to-grid volumes



Over 3% of hours remain excluded due to missing data or insufficient source assets

- 8,760 simulations were attempted for calculation of losses in initial state
- 9 hours (0.1%) could not solve due to missing data
  - Now identified as XA-MISSIN in Workbook
- 60 hours (0.7%) could not solve due to insufficient source assets to balance load in initial state
- 224 hours (2.6%) could not solve due to insufficient source assets to balance load in redispatched state
  - Hour is excluded for all assets if any simulation in hour fails to solve due to insufficient source assets
- Total of 293 hours (3.3%) excluded due to missing data or insufficient source assets to balance load

About 52% of all hours and locations had dispatch and sufficient assets to solve

Hours (×121)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Total hours	90,024	81,312	89,903	87,120	90,024	87,120	90,024	90,024	87,120	90,024	87,241	90,024	1,059,960
Missing	0	0	0	0	0	(484)	0	(242)	0	0	(121)	(242)	(1,089)
Insufficient initial	0	0	0	0	(2,662)	(484)	0	(484)	(2,541)	(1,089)	0	0	(7,260)
Insufficient redispatched	0	0	0	(325)	(2,159)	(1,114)	(1,210)	(4,691)	(2,378)	(2,728)	(421)	(126)	(15,152)
No dispatch	(41,466)	(36,795)	(40,928)	(41,263)	(40,145)	(38,797)	(40,181)	(40,517)	(40,069)	(43,277)	(42,244)	(40,434)	(486,116)
Potential hours	48,558	44,517	48,975	45,532	45,058	46,241	48,633	44,090	42,132	42,930	44,455	49,222	550,343

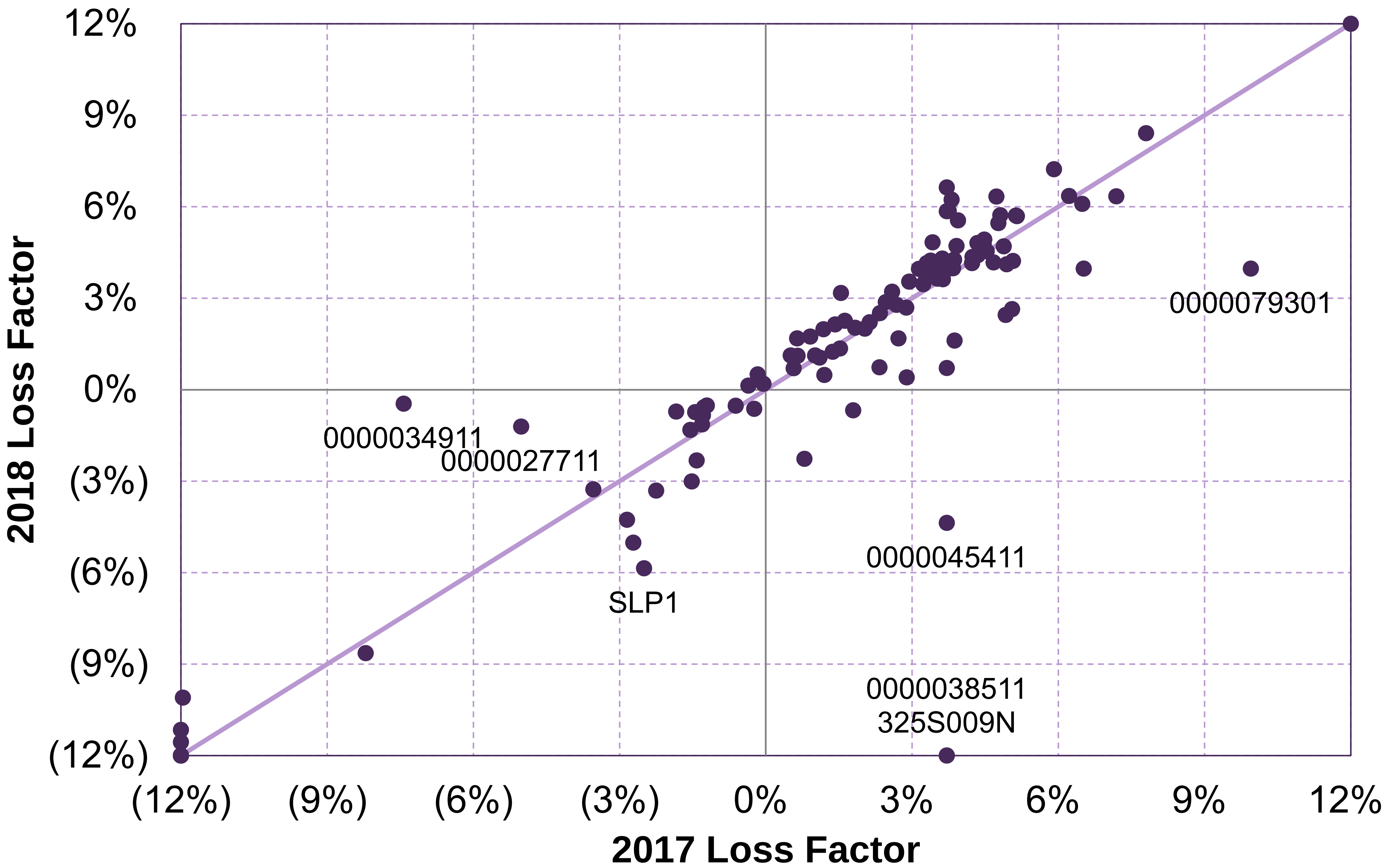
Percentages	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Total hours	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Missing	0.0%	0.0%	0.0%	0.0%	0.0%	(0.6%)	0.0%	(0.3%)	0.0%	0.0%	(0.1%)	(0.3%)	(0.1%)
Insufficient initial	0.0%	0.0%	0.0%	0.0%	(3.0%)	(0.6%)	0.0%	(0.5%)	(2.9%)	(1.2%)	0.0%	0.0%	(0.7%)
Insufficient redispatched	0.0%	0.0%	0.0%	(0.4%)	(2.4%)	(1.3%)	(1.3%)	(5.2%)	(2.7%)	(3.0%)	(0.5%)	(0.1%)	(1.4%)
No dispatch	(46.1%)	(45.3%)	(45.5%)	(47.4%)	(44.6%)	(44.5%)	(44.6%)	(45.0%)	(46.0%)	(48.1%)	(48.4%)	(44.9%)	(45.9%)
Potential hours	53.9%	54.7%	54.5%	52.3%	50.1%	53.1%	54.0%	49.0%	48.4%	47.7%	51.0%	54.7%	51.9%

About 99% of all potential hours solved, with about 10% more excluded in same hours

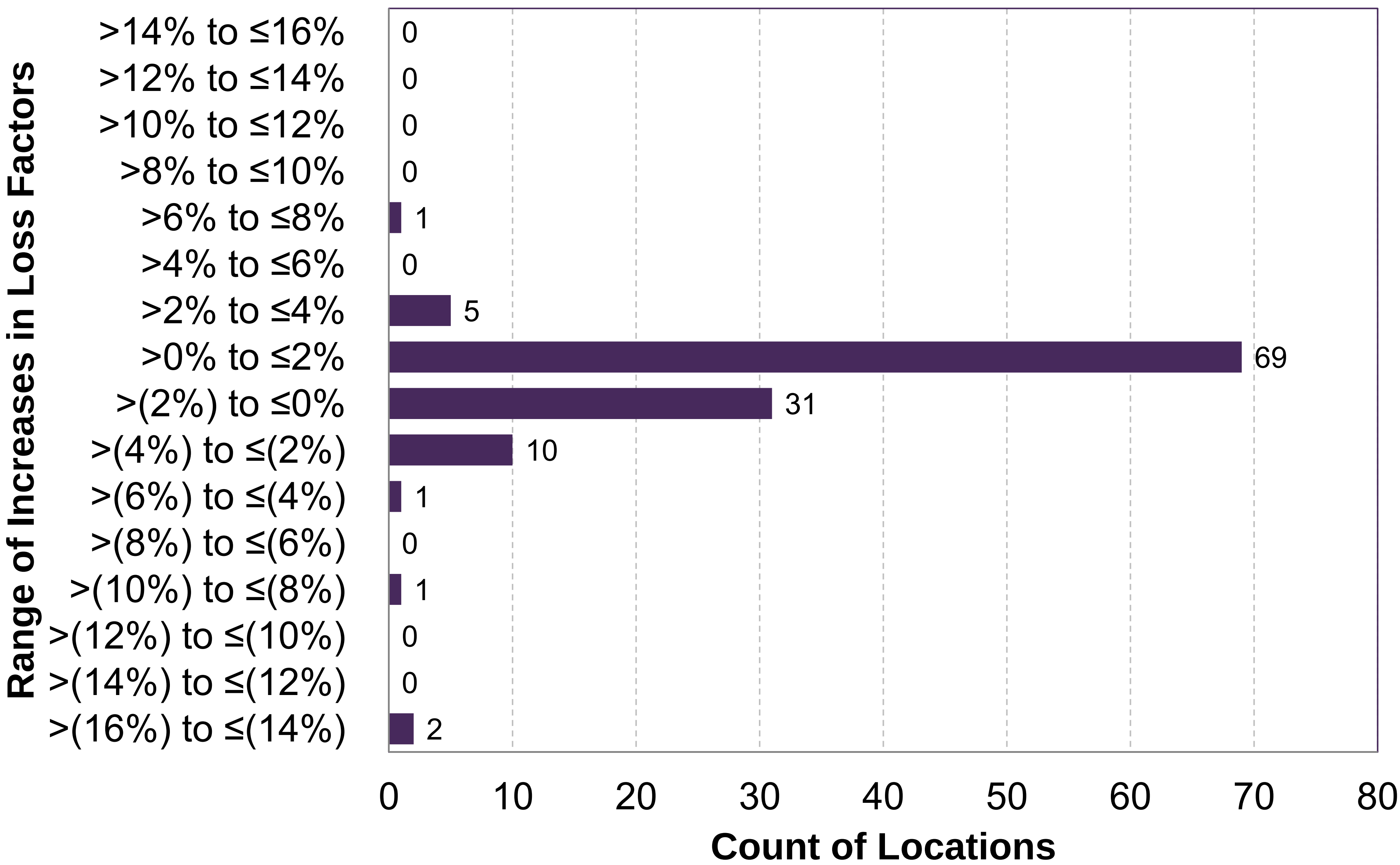
Hours (×121)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Potential hours	48,558	44,517	48,975	45,532	45,058	46,241	48,633	44,090	42,132	42,930	44,455	49,222	550,343
Unsolved initial	(847)	(242)	(363)	(363)	0	(121)	(121)	(242)	(484)	(242)	0	0	(3,025)
Unsolved redispatched	(122)	(301)	(40)	(46)	(354)	(569)	(377)	(960)	(233)	(232)	(543)	(153)	(3,930)
Unsolved elsewhere	(2,278)	(3,945)	(1,977)	(2,169)	(3,270)	(8,651)	(6,401)	(8,073)	(5,367)	(4,446)	(5,025)	(4,794)	(56,396)
Solved hours	45,311	40,029	46,595	42,954	41,434	36,900	41,734	34,815	36,048	38,010	38,887	44,275	486,992

Percentages	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Potential hours	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Unsolved initial	(1.7%)	(0.5%)	(0.7%)	(0.8%)	0.0%	(0.3%)	(0.2%)	(0.5%)	(1.1%)	(0.6%)	0.0%	0.0%	(0.5%)
Unsolved redispatched	(0.3%)	(0.7%)	(0.1%)	(0.1%)	(0.8%)	(1.2%)	(0.8%)	(2.2%)	(0.6%)	(0.5%)	(1.2%)	(0.3%)	(0.7%)
Unsolved elsewhere	(4.7%)	(8.9%)	(4.0%)	(4.8%)	(7.3%)	(18.7%)	(13.2%)	(18.3%)	(12.7%)	(10.4%)	(11.3%)	(9.7%)	(10.2%)
Solved hours	93.3%	89.9%	95.1%	94.3%	92.0%	79.8%	85.8%	79.0%	85.6%	88.5%	87.5%	89.9%	88.5%

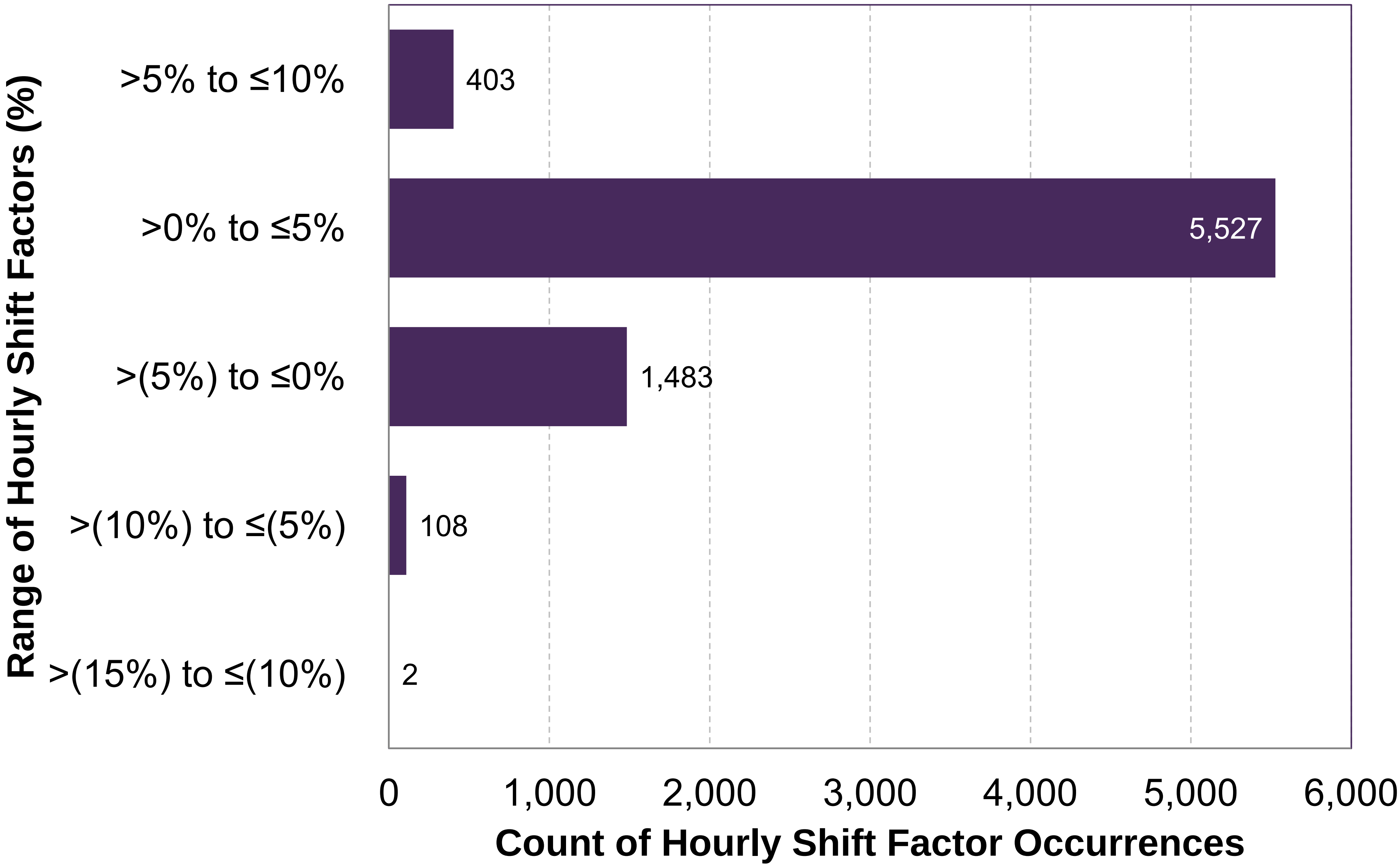
2018 loss factors are similar to 2017 loss factors except for very small generators



Over 80% of loss factors changed by less than ±2%, compared to 2017



About 93% of hourly shift factors were within ±5% of zero



Loss factor base cases are developed from current operational base case

1. Current operational base case is used as starting point
2. Operational base case is updated using project data update packages relevant to the base cases based on latest available in-service dates
3. Base cases are updated to incorporate capital maintenance of transmission facility owners
4. Base cases are updated to include projects in accordance with the loss factor rule project inclusion criteria
5. Finally, base cases are modified to create loss factor base cases by collapsing industrial system facilities and modifying other locations in accordance with the loss factor rule

Hourly system losses are determined through a multi-step process

- Input data is first collected and checked
  - Hourly energy market merit order data
  - Hourly load data
  - Hourly net-to-grid billing data for industrial systems
  - Monthly topology base cases
  - Validation information
    - Loss factor location list
    - Industrial system list
    - Measurement point definitions
    - Reactive power data for loads

After data is collected, input data files are prepared

- Base cases are prepared for loss factor calculations
  - Industrial systems are simplified to the transmission system interface bus
- Generator mapping files allow generating facilities in the merit order files to be assigned to generators in the PSS/E base cases
- Load mapping files allow load facilities in the load data file to be assigned to loads in the PSS/E base cases
- Hourly net-to-grid billing data is collected where necessary to handle industrial systems that offer on gross basis in merit order
- Measurement point definitions are used to validate changes in metering

Initial state is then calculated for all hours

- Base case is loaded into PSS/E and solution parameters are initialized
- All generators and loads are turned off in PSS/E
- Generation and load data for hour are loaded into PSS/E using estimate of system load
  - All generators and loads with data are turned on during loading
- Case is solved with WECC generator used as swing bus
  - Iterations with generation incremented up or down merit order until BC intertie flow is at hourly value
  - XA-MISSIN, XA-INSUF1, XA-UNSOL1 code identified if unsolvable

Initial state is then calculated for all hours
(cont'd)

- HVDC line flow is optimized and case is solved again
  - Iterations with generation incremented up or down merit order until BC intertie flow is at hourly value
  - XA-UNSOL1 code identified if unsolvable
- Industrial systems rebalanced if necessary to restore net-to-grid flows
- Case is solved with marginal unit as swing bus
  - XA-INSUF1, XA-UNSOL1 code identified if unsolvable
- Initial state solved case is saved
  - Other interim saves occur throughout process

Initial state is then calculated for all hours
(cont'd)

- Initial state information is recorded
  - Total system losses (MW)
  - Marginal unit and block number
  - Total system load (MW)
  - Exclusion code
  - Other interim information is recorded throughout process
- Initial state calculation is repeated for each hour

Redispatched state is calculated for each generator for each hour

- Initial state base case for hour is loaded into PSS/E and re-solved
  - WECC generator is used as swing bus
- Net-to-grid flow for generator of interest is reduced to zero
  - XS-NODISP code identified if initial flow is less than 1 MW
- Additional generation is dispatched up the merit order to rebalance the system
  - Any remaining MWs in marginal unit block are dispatched
  - MWs from next-in-merit unit block are dispatched
  - Process is repeated until BC intertie flow returns to initial state value
  - XA-INSUF2, XS-UNSOL2, XA-UNSOL2 code identified if unsolvable

Redispatched state is calculated for each generator for each hour (cont'd)

- HVDC line flow is optimized and case is solved again
  - Iterations until BC intertie flow returns to initial state value
  - XA-INSUF2, XS-UNSOL2, XA-UNSOL2 code identified if unsolvable
- Case is solved with marginal unit as swing bus
- Redispatched state solved case is saved
  - Other interim saves occur throughout process
- Redispatched state information is recorded
  - Total system losses (MW)
  - Exclusion code
  - Other interim information is recorded throughout process
- Redispatched state calculation is repeated for next generator

Example data for initial state calculation

Initial State for 2018/12/07 Hour Starting 17:00	
Dispatched generation	10,674.8 MW
Total load (MW)	10,365.9 MW
Industrial system load	1,762.8 MW
Non-industrial system load	8,603.1 MW
AB-BC intertie flow	275.0 MW
AB-SK intertie flow	(34.0 MW)
AB-MT intertie flow	0.0 MW
Initial state Alberta losses	274.9 MW
Initial state non-system losses	17.4 MW
Initial state system losses	257.5 MW
Initial state marginal unit	VVW2 – Block -1

Example data for redispatched state calculation

Redispatched State for MKRC 2018/12/07 Hour Starting 17:00	
Generator of interest (MPID)	MKRC
Initial volume of MPID	179.2 MW
Redispatched volume of MPID	0.0 MW
Redispatched state Alberta losses	268.7 MW
Redispatched state non-system losses	17.8 MW
Redispatched state system losses	250.9 MW
Redispatched state marginal unit	SCTG – Block -1

Example iterations for redispatched state calculation

Step	Asset	Initial MW	Updated MW	Losses MW	AB-BC Flow
1. Initial state for hour	—	—	—	274.9	275.0
2. MKRC reduced	MKRC	205.0	25.8	268.5	448.0
3. VVW2 increased	VVW2	45.6	48.0	268.4	445.0
4. BRA increased	BRA	280.0	295.0	269.1	431.0
5. NOVAGEN15M increased	N’15M	306.2	321.2	269.1	416.0
6. CMH1 increased	CMH1	205.0	220.0	269.2	401.0
7. SPR increased	SPR	23.0	35.0	269.0	389.0
8. NOVAGEN15M increased	N’15M	321.2	332.2	269.1	378.0
9. VVW1 increased	VVW1	30.0	41.0	268.4	366.0
10. BRA increased	BRA	295.0	305.0	268.9	357.0
11. CES1 increased	CES1	244.0	254.0	268.9	347
12. NOVAGEN15M increased	N’15M	332.2	342.2	269.0	337.0

Example iterations for redispatched state calculation (cont'd)

Step	Asset	Initial MW	Updated MW	Losses MW	AB-BC Flow
13. NX01 increased	NX01	96.0	106.0	269.0	327.0
14. SCTG increased	SCTG	219.0	229.0	269.0	317.0
15. CAS increased	CAS	18.0	27.0	268.9	308.0
16. TC01 increased	TC01	67.0	75.0	269.0	300.0
17. POC increased	POC	13.0	20.0	269.1	293.0
18. VVW1 increased	VVW1	41.0	48.0	268.7	286.0
19. BAR increased	BAR	13.0	19.0	268.7	280.0
20. SCTG increased	SCTG	229.0	233.5	268.7	275.0
21. SCTG as swing bus	SCTG	233.5	233.5	268.7	275.0
22. Optimize HVDC	SCTG	233.5	233.5	268.7	275.0

Merit order data used for example redispatched state

Asset	MPID	Block	Price	Size	Available
VVW2	VVW2	-1	999.99	18	18
BRA	BRA	-1	999.99	15	15
JOF1	NOVAGEN15M	-1	999.99	15	15
MEDHAT	CMH1	-1	999.99	15	15
ENCG	LSSi - Ignore	-1	999.99	13	13
BOW1.spr	SPR	-1	999.99	12	12
JOF1	NOVAGEN15M	-1	999.99	11	11
VVW1	VVW1	-1	999.99	11	11
BRA	BRA	-1	999.99	10	10
CAL1	CES1	-1	999.99	10	10
JOF1	NOVAGEN15M	-1	999.99	10	10
NX01	NX01	-1	999.99	10	10
SHELL	SCTG	-1	999.99	10	10
BOW1.cas	CAS	-1	999.99	9	9
ENOL	LSSi - Ignore	-1	999.99	9	9
TC01	TC01	-1	999.99	8	8
BOW1.poc	POC	-1	999.99	7	7
VVW1	VVW1	-1	999.99	7	7
BOW1.bar	BAR	-1	999.99	6	6
SHELL	SCTG	-1	999.99	6	6

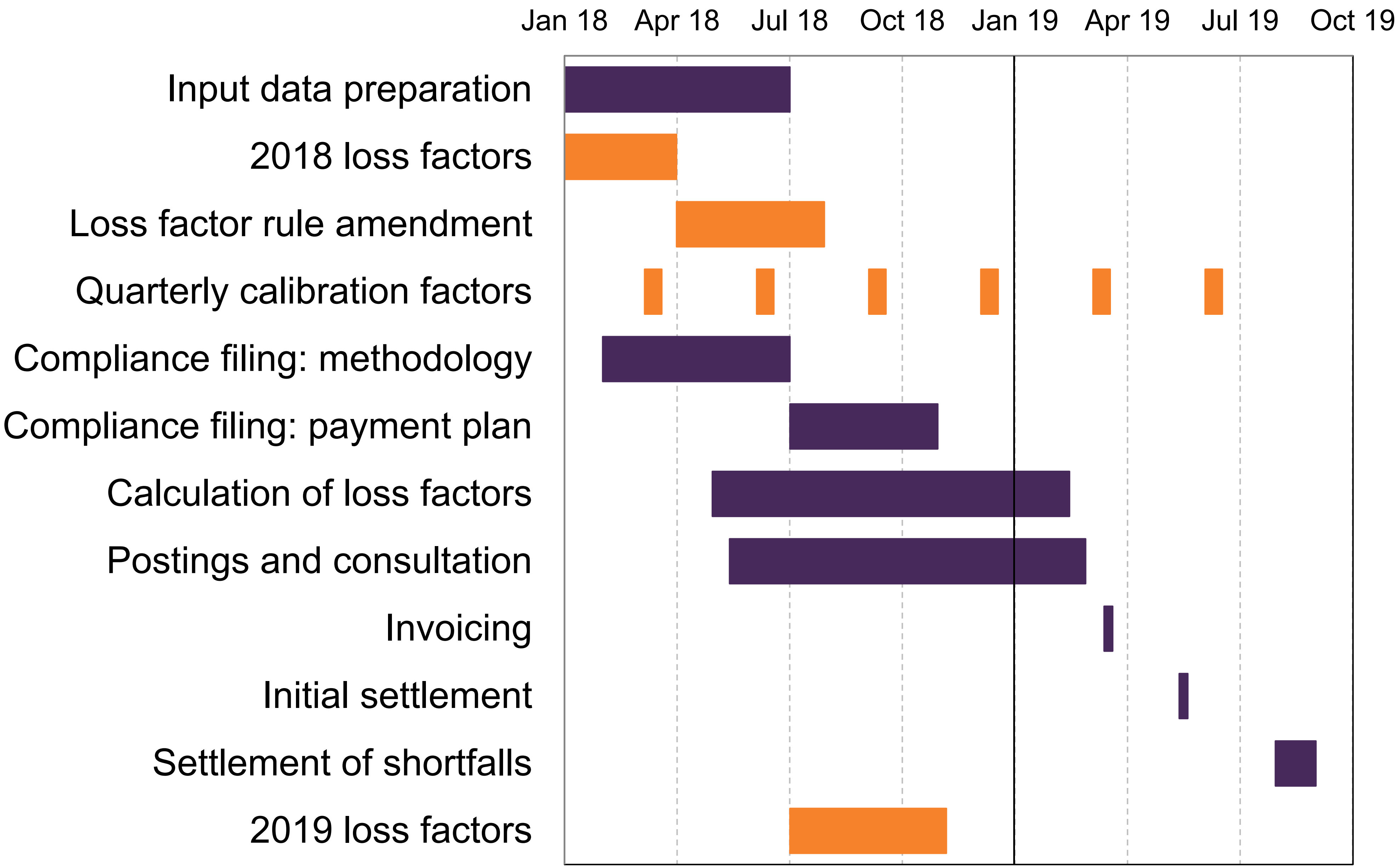
Raw loss factor for hour is calculated in loss factor workbook

- Data is written to loss factor workbook
- Workbook calculates hourly raw loss factor:

$$3.68\% = \frac{257.5 \text{ MW} - 250.9 \text{ MW}}{179.2 \text{ MW}}$$

- All hourly shifting, averaging, annual shifting, and compression in completed in workbook

Module C methodology compliance filing has been delayed



Discussion

- The AESO does not expect to provide written responses to questions asked during meeting

For more information

- John Martin
  Senior Tariff and Special Projects Advisor
  john.martin@aeso.ca
  403-539-2465
- Milton Castro-Nunez
  Senior Engineer, Transmission Program Support
  milton.castro-nunez@aeso.ca
  403-539-2537
- Loss factors, stakeholder consultation information, and related documents are posted on AESO website
  - Grid ► Loss factors ► 2018 loss factors
  - Grid ► Loss factors ► 2017-2018 loss factor development
  - Grid ► Loss factors ► Loss factors recalculation for 2006-2016

Thank you

Public