Efficient Available Transfer Capability Analysis Using Linear Methods

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What is Available Transfer Capability (ATC)?

- Some of you may be familiar with the terms
  - Total Transfer Capability (TTC)
  - Capacity Benefit Margin (CBM)
  - Transmission Reliability Margin (TRM)
  - "Existing Transmission Commitments"
  - Etc…
- Then ATC is defined as
  - ATC = TTC – CBM – TRM – "Existing TC"
- This talk will not cover these terms.
  - We will really be covering the calculation of "TTC", but let's not get caught up with the nomenclature.

Available Transfer Capability

- In broad terms, let's define ATC as
  - *The maximum amount of additional MW transfer possible between two parts of a power system*
    - *Additional* means that existing transfers are considered part of the "base case" and are not included in the ATC number
- Typically these two parts are control areas
  - Can really be any group of power injections.
- What does Maximum mean?
  - No overloads should occur in the system as the transfer is increased
  - No overloads should occur in the system *during contingencies* as the transfer is increased.

Computational Problem?

- Assume we want to calculate the ATC by incrementing the transfer, resolving the power flow, and iterating in this manner.
  - Assume 10 is a reasonable guess for number of iterations that it will take to determine the ATC
- We must do this process under each contingency.
  - Assume we have 600 contingencies.
- This means we have 10*600 power flows to solve.
- If it takes 30 seconds to solve each power flow (a reasonable estimate), then it will take 50 hours to complete the computation for ONE transfer direction!

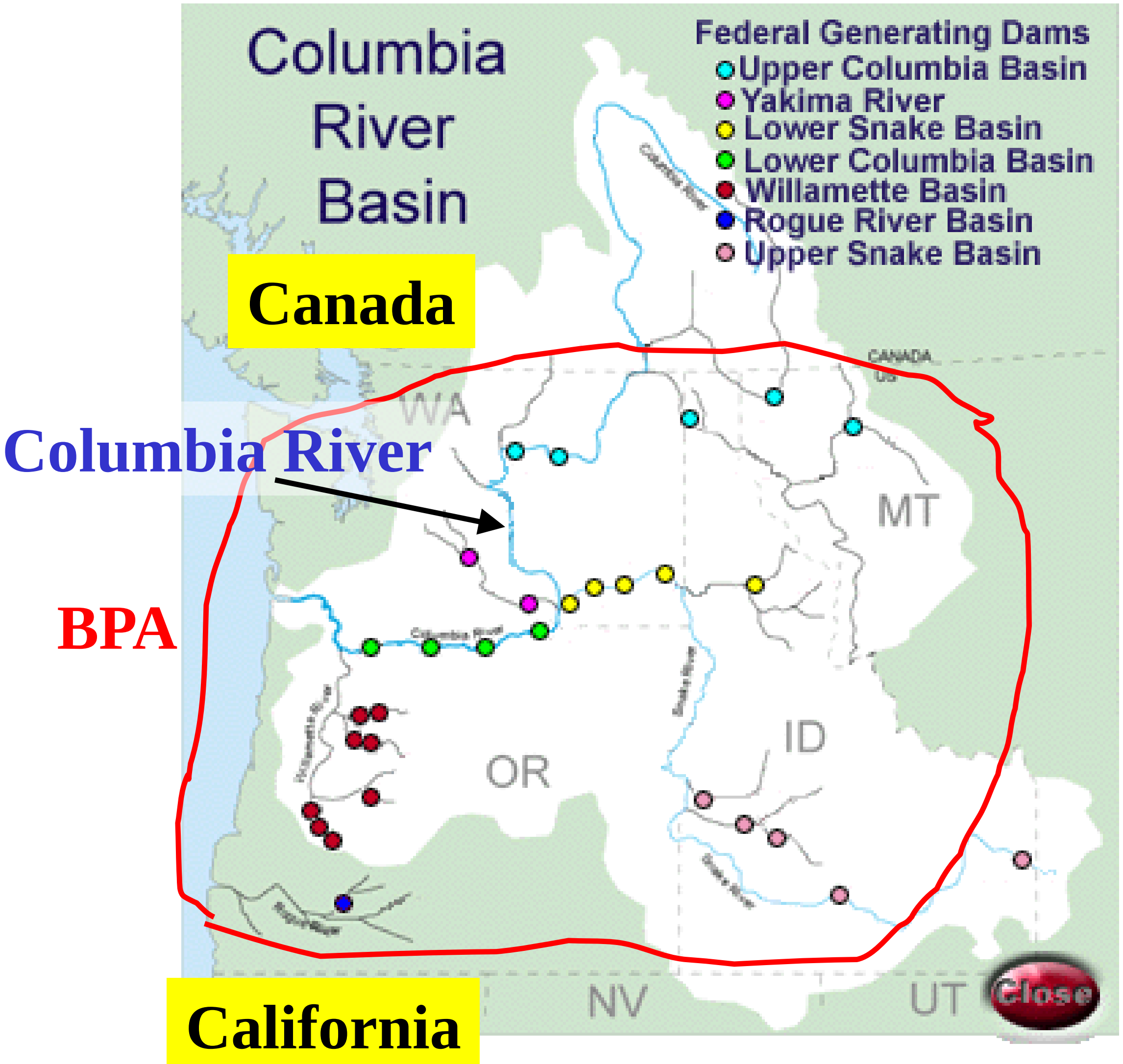
Why is ATC Important?

- It's the point where power system reliability meets electricity market efficiency.
- ATC can have a huge impact on market outcomes and system reliability, so the results of ATC are of great interest to all involved.

Example: The Bonneville Power Administration (BPA)

- BPA operates a HUGE capacity of hydro-electric generating stations
  - Example: The Grand Coulee Dam has a capacity of 6,765 MW (it's one dam!)
- Most of BPA's capacity is along the Columbia River which starts in Canada
- As a result, how Canada utilizes its part of the Columbia River has a huge impact on the ability of BPA to utilize its Hydro Units along the river

The Columbia River Basin



Columbia River Basin

- The United States and Canada operate the Columbia River under a Treaty Agreement
- To state the Treaty in highly over-simplified terms
  - Canada has built and operates Columbia River Dams to the benefit of the United States (i.e. BPA's hydro units)
  - BPA must make all attempts to give Canada access to markets in the US (i.e. California)
- This means BPA is always trying to ship power across its system between California and Canada.
- Huge amount of money is at stake
  - During the first 3 months of 2000, BC Hydro sold over $1 billion in electricity to California!

Linear Analysis Techniques in PowerWorld Simulator

An overview of the underlying mathematics of the power flow

Explanation of where the linearized analysis techniques come from

AC Power Flow Equations

- Full AC Power Flow Equations

$$\Delta P_k = 0 = V_k^2 g_{kk} + V_k \sum_{\substack{m=1 \\ m \neq k}}^{N} \left(V_m \left[g_{km} \cos(\delta_k - \delta_m) + b_{km} \sin(\delta_k - \delta_m) \right] \right) - P_{Gk} + P_{Lk}$$

$$\Delta Q_k = 0 = -V_k^2 b_{kk} + V_k \sum_{\substack{m=1 \\ m \neq k}}^{N} \left(V_m \left[g_{km} \sin(\delta_k - \delta_m) - b_{km} \cos(\delta_k - \delta_m) \right] \right) - Q_{Gk} + Q_{Lk}$$

- Solution requires iteration of equations

$$\begin{bmatrix} \Delta \boldsymbol{\delta} \\ \Delta \mathbf{V} \end{bmatrix} = \left[\begin{array}{c|c} \frac{\partial \mathbf{P}}{\partial \boldsymbol{\delta}} & \frac{\partial \mathbf{P}}{\partial \mathbf{V}} \\ \hline \frac{\partial \mathbf{Q}}{\partial \boldsymbol{\delta}} & \frac{\partial \mathbf{Q}}{\partial \mathbf{V}} \end{array} \right]^{-1} \begin{bmatrix} \Delta \mathbf{P} \\ \Delta \mathbf{Q} \end{bmatrix} = [\mathbf{J}]^{-1} \begin{bmatrix} \Delta \mathbf{P} \\ \Delta \mathbf{Q} \end{bmatrix}$$

- Note: the large matrix (J) is called the Jacobian

Full AC Derivatives

- Real Power derivative equations are

$$\frac{\partial P_k}{\partial \delta_m} = V_k V_m \left[-g_{km} \cos(\delta_k - \delta_m) - b_{km} \sin(\delta_k - \delta_m) \right]$$

$$\frac{\partial P_k}{\partial V_m} = V_k \left[g_{km} \sin(\delta_k - \delta_m) - b_{km} \cos(\delta_k - \delta_m) \right]$$

$$\frac{\partial P_k}{\partial \delta_k} = V_k \sum_{\substack{m=1 \\ m \neq k}}^{N} \left[V_m \left[-g_{km} \sin(\delta_k - \delta_m) + b_{km} \cos(\delta_k - \delta_m) \right] \right]$$

$$\frac{\partial P_k}{\partial V_k} = 2 V_k g_{kk} + \sum_{\substack{m=1 \\ m \neq k}}^{N} \left[V_m \left[g_{km} \cos(\delta_k - \delta_m) + b_{km} \sin(\delta_k - \delta_m) \right] \right]$$

- Reactive Power derivative equations are

$$\frac{\partial Q_k}{\partial \delta_m} = V_k V_m \left[-g_{km} \cos(\delta_k - \delta_m) - b_{km} \sin(\delta_k - \delta_m) \right]$$

$$\frac{\partial Q_k}{\partial V_m} = V_k \left[g_{km} \sin(\delta_k - \delta_m) - b_{km} \cos(\delta_k - \delta_m) \right]$$

$$\frac{\partial Q_k}{\partial \delta_k} = V_k \sum_{\substack{m=1 \\ m \neq k}}^{N} \left[V_m \left[g_{km} \cos(\delta_k - \delta_m) + b_{km} \sin(\delta_k - \delta_m) \right] \right]$$

$$\frac{\partial Q_k}{\partial V_k} = -2 V_k b_{kk} + \sum_{\substack{m=1 \\ m \neq k}}^{N} \left[V_m \left[g_{km} \sin(\delta_k - \delta_m) - b_{km} \cos(\delta_k - \delta_m) \right] \right]$$

Decoupled Power Flow Equations

- Make the following assumptions

$$\delta_k - \delta_m \approx 0 \qquad V_k \approx 1 \qquad r_{km} << x_{km}$$

$$\rightarrow \cos(\delta_k - \delta_m) \approx 1$$

$$\rightarrow \sin(\delta_k - \delta_m) \approx 0$$

$$\rightarrow g_{km} \approx 0$$

- Derivates simplify to

$$\frac{\partial P_k}{\partial \delta_k} = \sum_{\substack{m=1 \\ m \neq k}}^{N} b_{km} \qquad \frac{\partial P_k}{\partial \delta_m} = -b_{km} \qquad \frac{\partial P_k}{\partial V_k} = 0 \qquad \frac{\partial P_k}{\partial V_m} = 0$$

$$\frac{\partial Q_k}{\partial V_k} = -2b_{kk} + \sum_{\substack{m=1 \\ m \neq k}}^{N} (-b_{km}) \qquad \frac{\partial Q_k}{\partial V_m} = -b_{km} \qquad \frac{\partial Q_k}{\partial \delta_k} = 0 \qquad \frac{\partial Q_k}{\partial \delta_m} = 0$$

B' and B'' Matrices

- Define $\frac{\partial \mathbf{P}}{\partial \boldsymbol{\delta}} = \mathbf{B}^{'}$ and $\frac{\partial \mathbf{Q}}{\partial \mathbf{V}} = \mathbf{B}^{''}$
- Now Iterate the "decoupled" equations

$$\Delta\boldsymbol{\delta} = \left[\mathbf{B}^{'}\right]^{-1} \Delta\mathbf{P}$$

$$\Delta\mathbf{V} = \left[\mathbf{B}^{''}\right]^{-1} \Delta\mathbf{Q}$$

- What are B' and B''? After a little thought, we can simply state that…
  - B' is the imaginary part of the Y-Bus with all the "shunt terms" removed
  - B'' is the imaginary part of the Y-Bus with all the "shunt terms" double counted

"DC Power Flow"

- The "DC Power Flow" equations are simply the real part of the decoupled power flow equations
  - Voltages and reactive power are ignored
  - Only angles and real power are solved for by iterating

$$\Delta\boldsymbol{\delta} = \left[\mathbf{B}'\right]^{-1}\Delta\mathbf{P}$$

Bus Voltage and Angle Sensitivities to a Transfer

- Power flow was solved by iterating $\begin{bmatrix} \Delta\boldsymbol{\delta} \\ \Delta\mathbf{V} \end{bmatrix} = [\mathbf{J}]^{-1} \begin{bmatrix} \Delta\mathbf{P} \\ \Delta\mathbf{Q} \end{bmatrix}$
- Model the transfer as a change in the injections ΔP
  - Buyer: $\Delta\mathbf{T}_B = [0 \quad 0 \quad PF_{Bf} \quad 0 \quad PF_{Bg} \quad 0]^T \qquad \sum_{h=1}^{N} PF_{Bh} = 1$
  - Seller: $\Delta\mathbf{T}_S = [0 \quad PF_{Sx} \quad 0 \quad PF_{Sy} \quad 0 \quad 0]^T \qquad \sum_{z=1}^{N} PF_{Sz} = 1$
- Assume buyer consists of
  - 85% from bus 3 and 15% from bus 5, then

$$\Delta\mathbf{T}_B = [\; 0 \quad 0 \quad 0.85 \quad 0 \quad 0.15 \quad 0 \;]^T$$

- Assume seller consists of
  - 65% from bus 2 and 35% from bus 4, then

$$\Delta\mathbf{T}_S = [\; 0 \quad 0.65 \quad 0 \quad 0.35 \quad 0 \quad 0 \;]^T$$

Bus Voltage and Angle Sensitivities to a Transfer

- Then solve for the voltage and angle sensitivities by solving

$$\begin{bmatrix} \Delta\boldsymbol{\delta}_S \\ \Delta\mathbf{V}_S \end{bmatrix} = [\mathbf{J}]^{-1} \begin{bmatrix} \Delta\mathbf{T}_S \\ \mathbf{0} \end{bmatrix} \qquad \begin{bmatrix} \Delta\boldsymbol{\delta}_B \\ \Delta\mathbf{V}_B \end{bmatrix} = [\mathbf{J}]^{-1} \begin{bmatrix} \Delta\mathbf{T}_B \\ \mathbf{0} \end{bmatrix}$$

- $\Delta\boldsymbol{\delta}_S, \Delta\boldsymbol{\delta}_B, \Delta\mathbf{V}_S,$ and $\Delta\mathbf{V}_B$ are the sensitivities of the Buyer and Seller "sending power to the slack bus"

What about Losses?

- If we assume the total sensitivity to the transfer is the seller minus the buyer sensitivity, then

$$\Delta\boldsymbol{\delta} = \Delta\boldsymbol{\delta}_S - \Delta\boldsymbol{\delta}_B \qquad \Delta\mathbf{V} = \Delta\mathbf{V}_S - \Delta\mathbf{V}_B$$

- Implicitly, this assumes that ALL the change in losses shows up at the slack bus.
- PowerWorld Simulator assigns the change to the BUYER instead by defining

$$k = \frac{\Delta Slack_S}{\Delta Slack_B} = \frac{\text{Change in slack bus generation for seller sending power to slack}}{\text{Change in slack bus generation for buyer sending power to slack}}$$

- Then

$$\begin{bmatrix} \Delta\boldsymbol{\delta} \\ \Delta\mathbf{V} \end{bmatrix} = \begin{bmatrix} \Delta\boldsymbol{\delta}_S \\ \Delta\mathbf{V}_S \end{bmatrix} - k \begin{bmatrix} \Delta\boldsymbol{\delta}_B \\ \Delta\mathbf{V}_B \end{bmatrix}$$

Lossless DC Voltage and Angle Sensitivities

- Use the DC Power Flow Equations

$$\Delta\boldsymbol{\delta} = \left[\mathbf{B}^{'}\right]^{-1}\Delta\mathbf{P}$$

- Then determine angle sensitivities

$$\Delta\boldsymbol{\delta}_S = \left[\mathbf{B}^{'}\right]^{-1}\Delta\mathbf{T}_S \qquad \Delta\boldsymbol{\delta}_B = \left[\mathbf{B}^{'}\right]^{-1}\Delta\mathbf{T}_B$$

- The DC Power Flow ignores losses, thus

$$\Delta\boldsymbol{\delta} = \Delta\boldsymbol{\delta}_S - \Delta\boldsymbol{\delta}_B$$

Lossless DC Sensitivities with Phase Shifters Included

- DC Power Flow equations $\left[\mathbf{B}^{'}\right]\Delta\boldsymbol{\delta} = \Delta\mathbf{P}$
- Augmented to include an equation that describes the change in flow on a phase-shifter controlled branch as being zero.

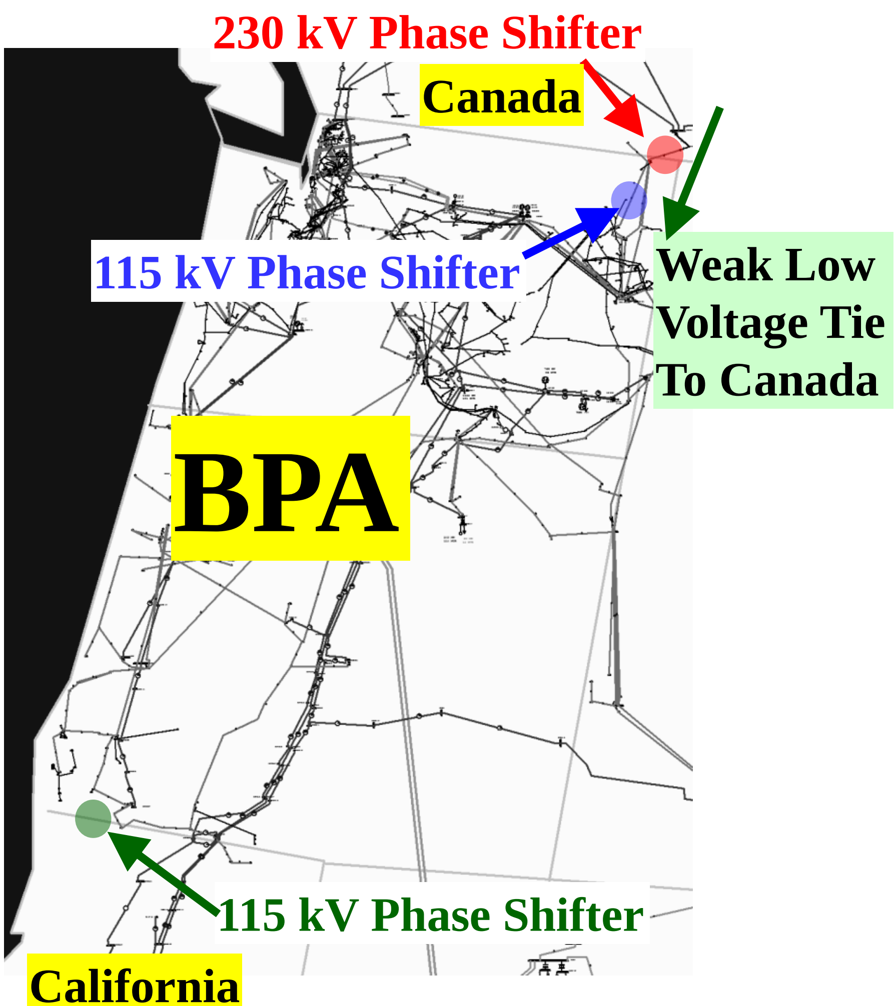
$$\text{Line Flow Change} = \mathbf{B}_{\delta}\Delta\boldsymbol{\delta} + \mathbf{B}_{\alpha}\Delta\boldsymbol{\alpha} = \mathbf{0}$$

- Thus instead of DC power flow equations we use

$$\begin{bmatrix} \Delta\boldsymbol{\delta} \\ \Delta\boldsymbol{\alpha} \end{bmatrix} = \begin{bmatrix} \mathbf{B}^{'} & \mathbf{0} \\ \mathbf{B}_{\delta} & \mathbf{B}_{\alpha} \end{bmatrix}^{-1} \begin{bmatrix} \Delta\mathbf{P} \\ \mathbf{0} \end{bmatrix}$$

- Otherwise process is the same.

Why Include Phase Shifters?



- Phase Shifters are often on lower voltage paths (230 kV or less) with relatively small limits
- They are put there in order to manage the flow on a path that would otherwise commonly see overloads
- Without including them in the sensitivity calculation, they constantly show up as “overloaded” when using Linear ATC tools

Power Transfer Distribution Factors (PTDFs)

- PTDF: measures the sensitivity of line MW flows to a MW transfer.
  - Line flows are simply a function of the voltages and angles at its terminal buses
  - Using the Chain Rule, the PTDF is simply a function of these voltage and angle sensitivities.
- P_{km} is the flow from bus k to bus m

$$PTDF = \Delta P_{km} = \left[\frac{\partial P_{km}}{\partial V_k}\right]\Delta V_K + \left[\frac{\partial P_{km}}{\partial V_m}\right]\Delta V_m + \left[\frac{\partial P_{km}}{\partial \delta_k}\right]\Delta \delta_K + \left[\frac{\partial P_{km}}{\partial \delta_m}\right]\Delta \delta_m$$

Voltage and Angle Sensitivities that were just discussed

P_{km} Derivative Calculations

- Full AC equations

$$\left[\frac{\partial P_{km}}{\partial \delta_m}\right] = V_k V_m \left[g_{km}\sin(\delta_k - \delta_m) - b_{km}\cos(\delta_k - \delta_m)\right]$$

$$\left[\frac{\partial P_{km}}{\partial \delta_k}\right] = V_k V_m \left[-g_{km}\sin(\delta_k - \delta_m) + b_{km}\cos(\delta_k - \delta_m)\right]$$

$$\left[\frac{\partial P_{km}}{\partial V_m}\right] = V_k \left[g_{km}\cos(\delta_k - \delta_m) + b_{km}\sin(\delta_k - \delta_m)\right]$$

$$\left[\frac{\partial P_{km}}{\partial V_k}\right] = 2V_k g_{kk} + V_m \left[g_{km}\cos(\delta_k - \delta_m) + b_{km}\sin(\delta_k - \delta_m)\right]$$

- Lossless DC Approximations yield

$$\left[\frac{\partial P_{km}}{\partial \delta_m}\right] = -b_{km} \qquad \left[\frac{\partial P_{km}}{\partial \delta_k}\right] = b_{km}$$

$$\left[\frac{\partial P_{km}}{\partial V_k}\right] = 0 \qquad \left[\frac{\partial P_{km}}{\partial V_m}\right] = 0$$

Line Outage Distribution Factors (LODFs)

- $LODF_{l,k}$: percent of the pre-outage flow on Line K will show up on Line L after the outage of Line K

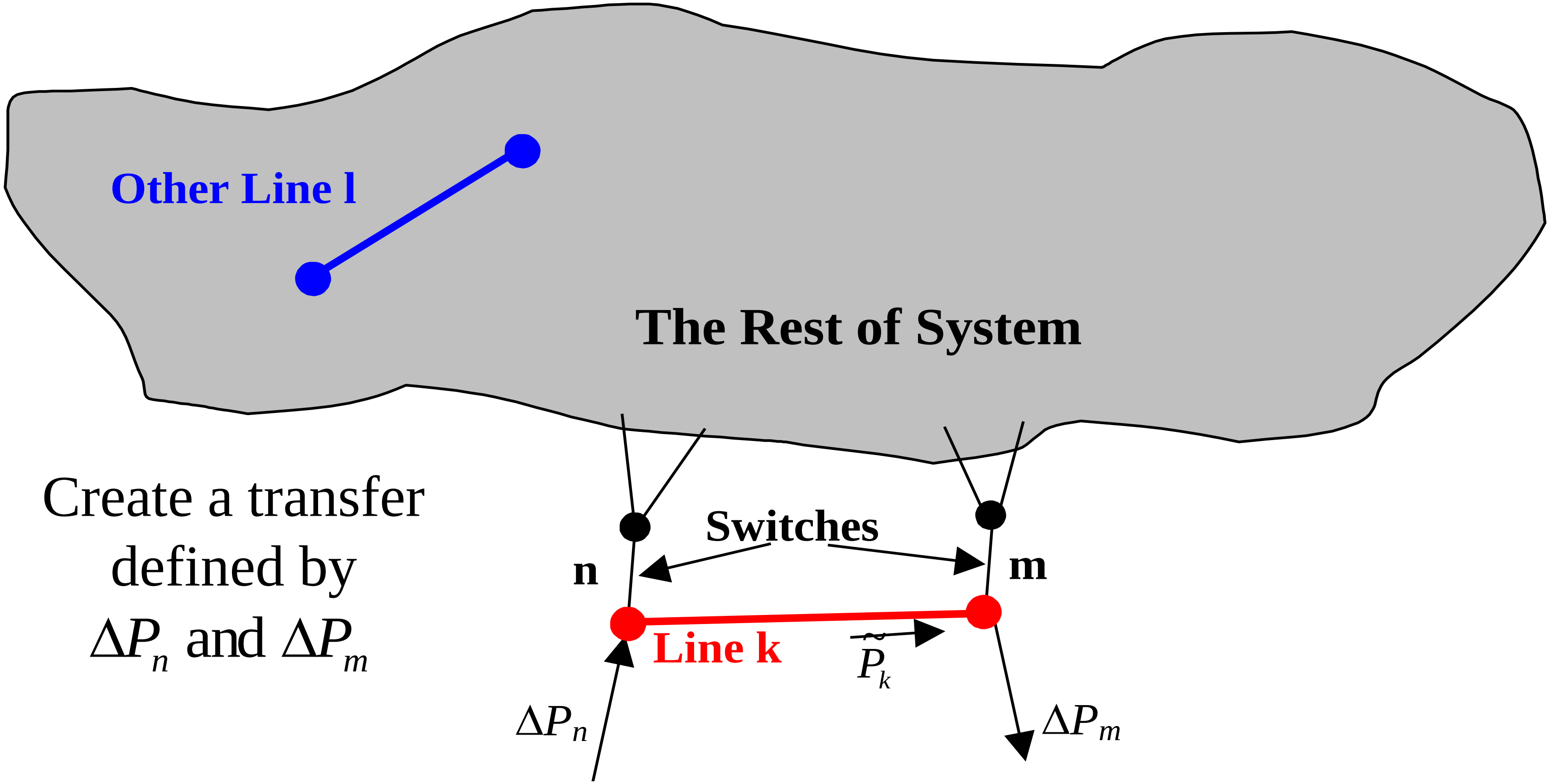
$$LODF_{l,k} = \frac{\Delta P_{l,k}}{P_k}$$

Change in flow on Line L after the outage of Line K ($\Delta P_{l,k}$)

Pre-outage flow on Line K (P_k)

- Linear impact of an outage is determined by modeling the outage as a "transfer" between the terminals of the line

Modeling an LODF as a Transfer



Create a transfer defined by ΔP_n and ΔP_m

Assume $\tilde{P}_k = \Delta P_n = \Delta P_m$
Then the flow on the Switches is ZERO, thus Opening Line K is equivalent to the "transfer"

Modeling an LODF as a Transfer

- Thus, setting up a transfer of $\tilde{P}_k$ MW from Bus n to Bus m is linearly equivalent to outaging the transmission line
- Let's assume we know what $\tilde{P}_k$ is equal to, then we can calculate the values relevant to the LODF
  - Calculate the relevant values by using PTDFs for a "transfer" from Bus n to Bus m.

Calculation of LODF

- Estimate of post-outage flow on Line L

$$\Delta P_{l,k} = PTDF_l * \tilde{P}_k$$

- Estimate of flow on Line K after transfer

$$\tilde{P}_k = P_k + PTDF_k * \tilde{P}_k \longrightarrow \tilde{P}_k = \frac{P_k}{1 - PTDF_k}$$

- Thus we can write

$$LODF_{l,k} = \frac{\Delta P_{l,k}}{P_k} = \frac{PTDF_l * \tilde{P}_k}{P_k} = \frac{PTDF_l * \left(\frac{P_k}{1 - PTDF_k} \right)}{P_k}$$

$$\longrightarrow LODF_{l,k} = \frac{PTDF_l}{1 - PTDF_k}$$

- We have a simple function of PTDF values

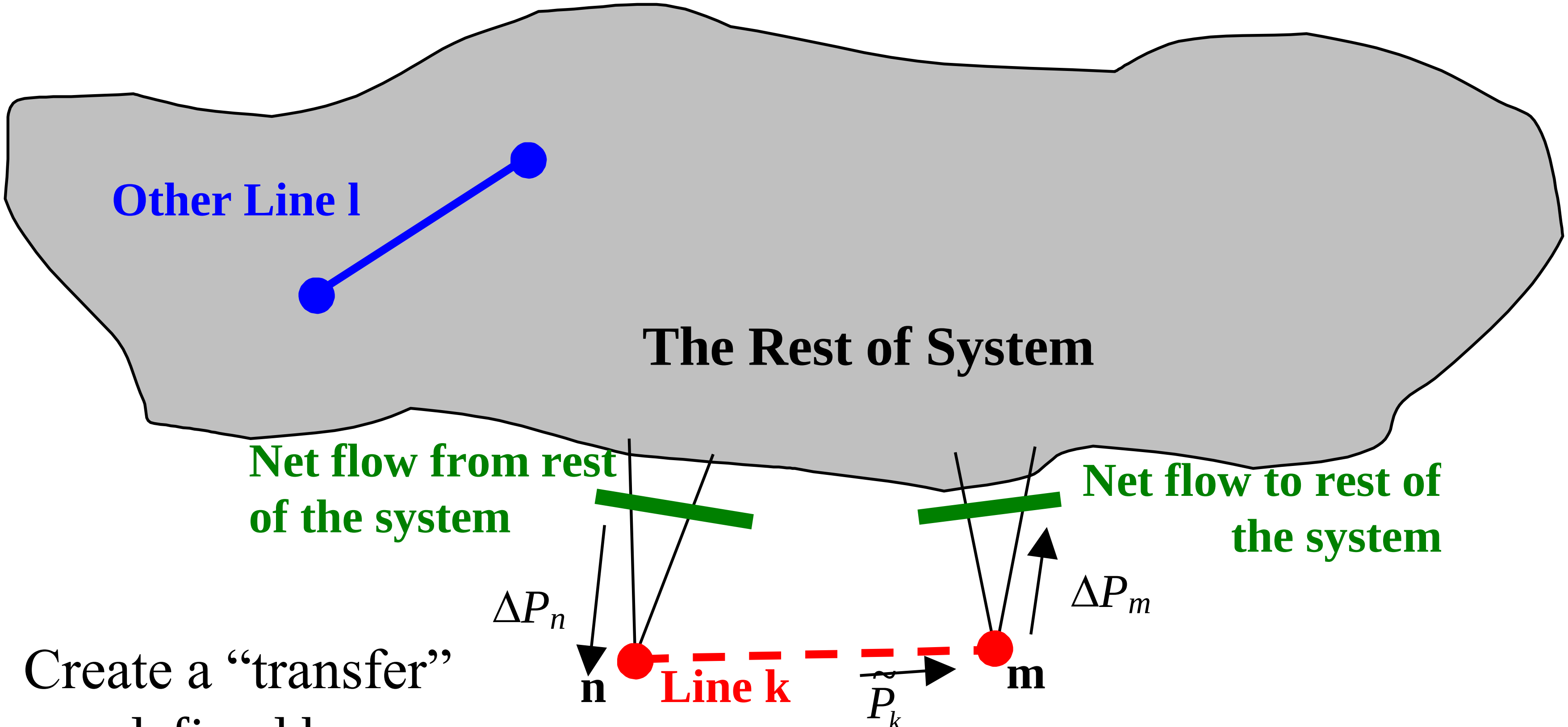
Line Closure Distribution Factors (LCDFs)

- $LCDF_{l,k}$: percent of the post-closure flow on Line K will show up on Line L after the closure of Line K

$$LCDF_{l,k} = \frac{\Delta P_{l,k}}{\tilde{P}_k}$$

- Linear impact of an closure is determined by modeling the closure as a “transfer” between the terminals of the line

Modeling the LCDF as a Transfer



Create a "transfer" defined by ΔP_n and ΔP_m

Assume $\tilde{P}_k = \Delta P_n = \Delta P_m$

Then the net flow to and from the rest of the system are both zero, thus closing line k is equivalent the "transfer"

Modeling an LCDF as a Transfer

- Thus, setting up a transfer of $-\tilde{P}_k$ MW from Bus n to Bus m is linearly equivalent to outaging the transmission line
- Let's assume we know what $-\tilde{P}_k$ is equal to, then we can calculate the values relevant to the LODF.
- Note: The negative sign is used so that the notation is consistent with the LODF "transfer" direction.

Calculation of LCDF

- Estimate of post-closure flow on Line L

$$\Delta P_{l,k} = PTDF_l * (-\tilde{P}_k)$$

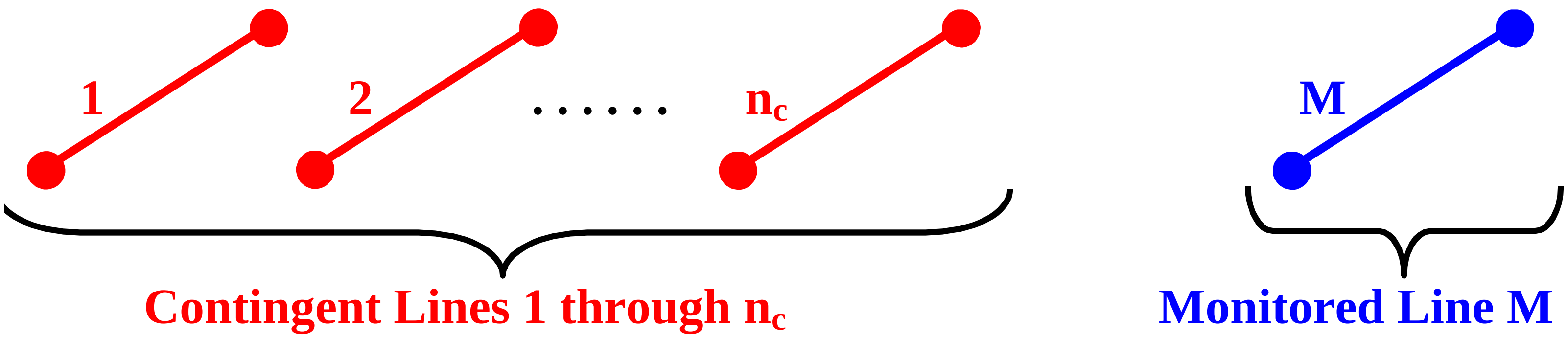
- Thus we can write

$$LCDF_{l,k} = \frac{\Delta P_{l,k}}{\tilde{P}_k} = \frac{-PTDF_l * \tilde{P}_k}{\tilde{P}_k} = -PTDF_l$$

$$\longrightarrow \quad LCDF_{l,k} = -PTDF_l$$

- Thus the *LCDF*, is exactly equal to the *PTDF* for a transfer between the terminals of the line

Modeling Linear Impact of a Contingency



- Outage Transfer Distribution Factors (OTDFs)
  - The percent of a transfer that will flow on a branch M after the contingency occurs
- Outage Flows (OMWs)
  - The estimated flow on a branch M after the contingency occurs

OTDFs and OMWs

- Single Line Outage

$$OTDF_{M,1} = PTDF_M + LODF_{M,1} * PTDF_1$$

$$OMW_{M,1} = MW_M + LODF_{M,1} * MW_1$$

- Multiple Line Outage

$$OTDF_{M,C} = PTDF_M + \sum_{K=1}^{n_C} \left[LODF_{MK} * NetPTDF_K \right]$$

$$OMW_{M,C} = MW_M + \sum_{K=1}^{n_C} \left[LODF_{MK} * NetMW_K \right]$$

- What are $NetPTDF_K$ and $NetMW_K$?

Determining $NetPTDF_K$ and $NetMW_K$

- Each $NetPTDF_K$ is a function of all the other *NetPTDFs* because the change in status of a line effects all other lines (including other outages).
- Assume we know all *NetPTDFs* except for the first one, $NetPTDF_1$. Then we can write:

$$NetPTDF_1 = PTDF_1 + LODF_{12} NetPTDF_2 + \ldots + LODF_{1n_C} NetPTDF_{n_C}$$

$$= PTDF_1 + \sum_{K=2}^{n_C} \left[LODF_{1K} NetPTDF_K \right]$$

- In general for each Contingent Line N, write

$$1.0 * NetPTDF_N - \sum_{\substack{K=1 \\ K \neq N}}^{n_C} \left[LODF_{NK} NetPTDF_K \right] = PTDF_N$$

Determining $NetPTDF_K$ and $NetMW_K$

- Thus we have a set of n_c equations and n_c unknowns (n_c= number of contingent lines)

Known Values

$$\begin{bmatrix} 1 & -LODF_{12} & -LODF_{13} & \cdots & -LODF_{1n_C} \\ -LODF_{21} & 1 & -LODF_{23} & \cdots & -LODF_{2n_C} \\ -LODF_{31} & -LODF_{32} & 1 & \cdots & -LODF_{3n_C} \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ -LODF_{n_C 1} & -LODF_{n_C 2} & -LODF_{n_C 3} & \cdots & 1 \end{bmatrix} \begin{bmatrix} NetPTDF_1 \\ NetPTDF_2 \\ NetPTDF_3 \\ \vdots \\ NetPTDF_{n_C} \end{bmatrix} = \begin{bmatrix} PTDF_1 \\ PTDF_2 \\ PTDF_3 \\ \vdots \\ PTDF_{n_C} \end{bmatrix}$$

- Thus $\mathbf{NetPTDF_C} = \left[\mathbf{LODF_{CC}}\right]^{-1} \mathbf{PTDF_C}$
- Same type of derivation shows

$$\mathbf{NetMW_C} = \left[\mathbf{LODF_{CC}}\right]^{-1} \mathbf{MW_C}$$

Fast ATC Analysis Goal = Avoid Power Flow Solutions

- When completely solving ATC, the number of power flow solutions required is equal to the product of
  - The number of contingencies
  - The number of iterations required to determine the ATC (this is normally smaller than the number of contingencies)
- We will look at three methods (2 are linearized)
  - Single Linear Step (fully linearized)
    - Perform a single power flow, then all linear (*extremely* fast)
  - Iterated Linear Step (mostly linear, Contingencies Linear)
    - Requires iterations of power flow to ramp out to the maximum transfer level, but no power flows for contingencies.
  - (IL) then Full AC
    - Requires iterations of power flow and full solution of contingencies

Single Linear Step ATC

- For each line in the system determine a Transfer Limiter Value T

$$T_M = \begin{cases} \dfrac{Limit_M - MW_M}{PTDF_M} & ; \quad PTDF_M > 0 \\ \infty \ \text{(infinite)} & ; \quad PTDF_M = 0 \\ \dfrac{-Limit_M - MW_M}{PTDF_M} & ; \quad PTDF_M < 0 \end{cases}$$

Single Linear Step ATC

- Then, for each line during each contingency determine another Transfer Limiter Value

$$T_{M,C} = \begin{cases} \dfrac{Limit_M - OMW_{M,C}}{OTDF_{M,C}} & ; \quad OTDF_{M,C} > 0 \\ \infty \ \text{(infinite)} & ; \quad OTDF_{M,C} = 0 \\ \dfrac{-Limit_M - OMW_{M,C}}{OTDF_{M,C}} & ; \quad OTDF_{M,C} < 0 \end{cases}$$

Important Sources of Error in Linear ATC Numbers

- Linear estimates of *OTDF* and *OMW* are quite accurate (usually within 2 %)
- But, this can lead to big errors in ATC estimates
  - Assume a line's present flow is 47 MW and its limit is 100 MW.
  - Assume *OTDF* = 0.5%; Assume *OMW* = 95 MW
  - Then *ATC* = (100 - 95) / 0.005 = 1000 MW
  - Assume 2% error in *OMW* (1 MW out of 50 MW change estimate)
    - Actual *OMW* is 96 MW
  - Assume 0% error in *OTDF*
  - Actual *ATC* is then (100-96)/0.005 = 800 MW
- 2% error in *OMW* estimate results in a 25% over-estimate of the *ATC*

Single Linear Step ATC

- The transfer limit can then be calculated to be the minimum value of T_M or $T_{M,C}$ for all lines and contingencies.
- Simulator saves several values with each Transfer Limiters
  - T_M or $T_{M,C}$ [Transfer Limit]
  - Line being monitored [Limiting Element]
  - Contingency [Limiting Contingency]
  - OTDF or PTDF value [%PTDF_OTDF]
  - OMW or MW value [Pre-Transfer Flow Estimate]
  - Limit Used (negative Limit if PTDF_OTDF < 0)
  - MW value initially [Initial Value]

Good for filtering out errors

Pros and Cons of the Linear Step ATC

- Single Linear Step ATC is *extremely* fast
  - Linearization is quite accurate in modeling the impact of contingencies and transfers
- However, it only uses derivatives around the present operating point. Thus,
  - Control changes as you ramp out to the transfer limit are NOT modeled
    - Exception: We made special arrangements for Phase Shifters
  - The possibility of generators participating in the transfer hitting limits is NOT modeled
- The, Iterated Linear Step ATC takes into account these control changes.

Iterated Linear (IL) Step ATC

- Performs the following

  1. Stepsize = ATC using Single Linear Step
  2. If [abs(stepsize) < Tolerance] then stop
  3. Ramp transfer out an additional amount of Stepsize
  4. Resolve Power Flow (slow part, but takes into account all controls)
  5. At new operating point, Stepsize = ATC using Single Linear Step
  6. Go to step 2

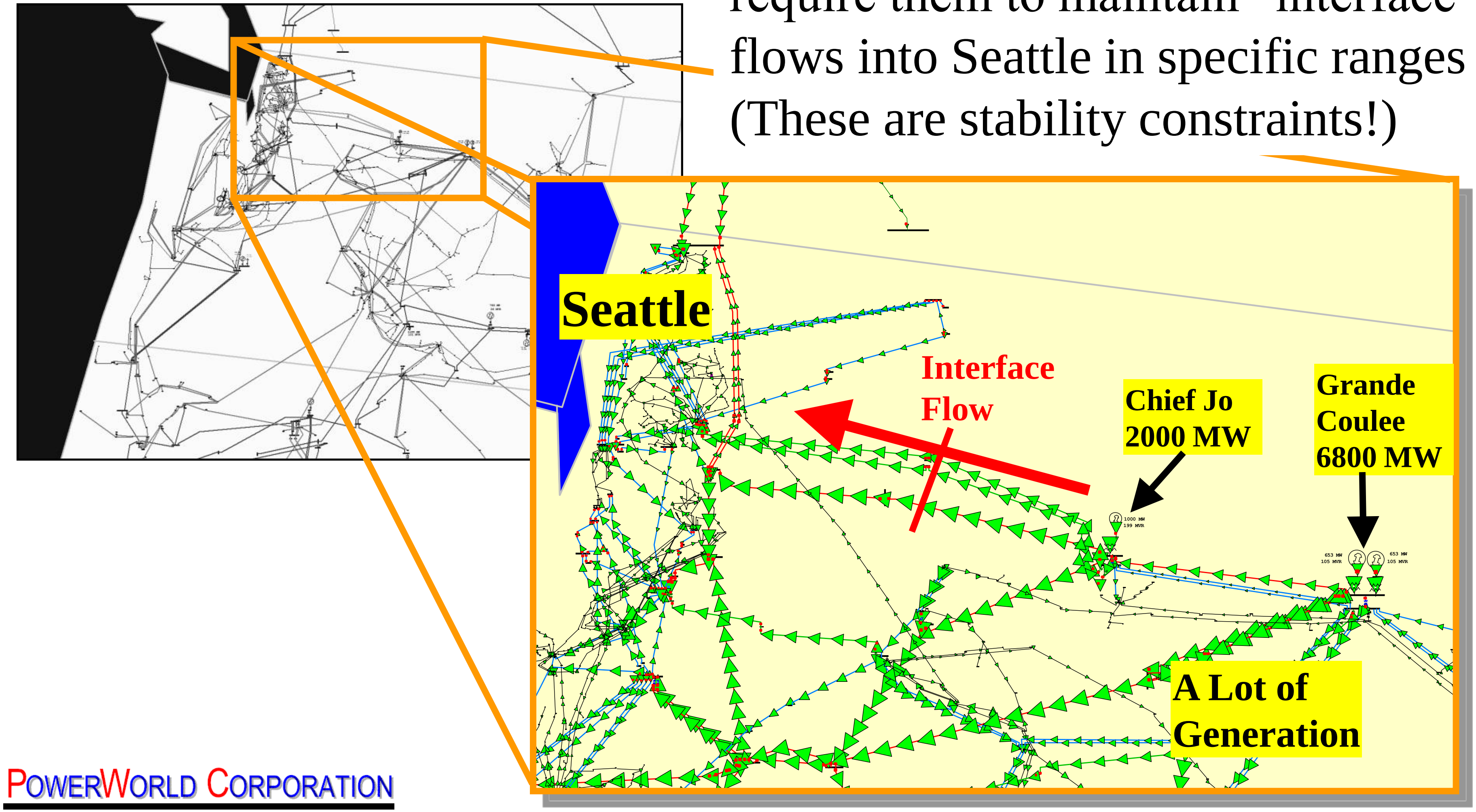
- Reasonably fast
  - On the order of 10 times slower than Single Linear Step
- Takes into account all control changes because a full AC Power Flow is solved to ramp the transfer

Including OPF constraints in (IL) to enforce Interface Flows

- When ramping out the transfer, Simulator can be set to enforce a specified flow on an interface.
- This introduces a radical change in control variables that is best modeled by completely resolving using the OPF
  - The objective of the OPF is to minimize the total controller changes (sum of generator output changes)
- Why would you do this?
  - Represent a normal operating guideline that is obeyed when transfers are changed.

Example: Bonneville Power Administration (BPA)

Operating procedures for BPA require them to maintain “interface” flows into Seattle in specific ranges (These are stability constraints!)



(IL) then Full AC Method

- Performs the following
  1. Run Iterated Linear Step and ramp transfer out ATC Value found
  2. StepSize = 10% of the initial Linear Step Size saved during the (IL) method, or 50 MW whichever is larger.
  3. Run Full Contingency Analysis on the ramped transfer state
  4. If there are violations then change the sign of Stepsize
  5. if [abs(stepsize) < Tolerance] then Stop
  6. Ramp transfer out an additional amount of Stepsize and resolve Power Flow
  7. At new operating point, Run Full Contingency Analysis
  8. if [(Stepsize > 0) and (There are Violation)] OR
[(Stepsize < 0) and (There are NO Violations)] THEN
StepSize := -StepSize/2
  9. Go to step 5
- *Extremely* slow.
  - "Number of Contingencies" times slower than the iterated linear. If you have 100 contingencies, then this is 100 times slower. (1 hour becomes 4 days!)

Recommendations from PowerWorld's Experience

- Single Linear Step
  - Use for all preliminary analysis, and most analysis in general.
- Iterated Linear Step
  - Only use if you know that important controls change as you ramp out to the limit
- (IL) then Full AC
  - Never use this method. It's just too slow.
  - The marginal gain in accuracy compared to (IL) (less than 2%) doesn't justify the time requirements
  - Remember that ATC numbers probably aren't any more than 2% accurate anyway! (what limits did you choose, what generation participates in the transfer, etc…)