# Recovering fixed costs in electricity markets

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# Overview

- Investment in Electricity Markets
  - Missing Money
  - Investment Equilibrium
    - SRMC Offering
    - LRMC Offering

- Transmission Pricing
  - Proposed TPM changes
  - Potential Shortcomings
  - Benefits of Transmission Expansion
  - EPOC's users pay proposal.

# Missing Money?

*Suppose electricity markets did not suffer from demand-side flaws. In particular, suppose demand is sufficiently responsive to prices, such that the wholesale electricity market always clears. Then, the market would be perfectly reliable: if supply is scarce, the price would rise until there is enough voluntary load reduction to absorb the scarcity. Consumers would never suffer involuntary rationing.*

*Yet, current electricity markets do not reflect this textbook ideal of guaranteed market clearing. The main problem is a lack of real-time meters and billing and other equipment to allow consumers to see and respond to real-time prices, resulting in low demand flexibility. Because storage of electricity is costly, the supply side is also inelastic as capacity becomes scarce…As a result, there is a possibility of non-price rationing of demand in the form of a rolling blackout…*

Cramton, Ockenfels and Stoft.

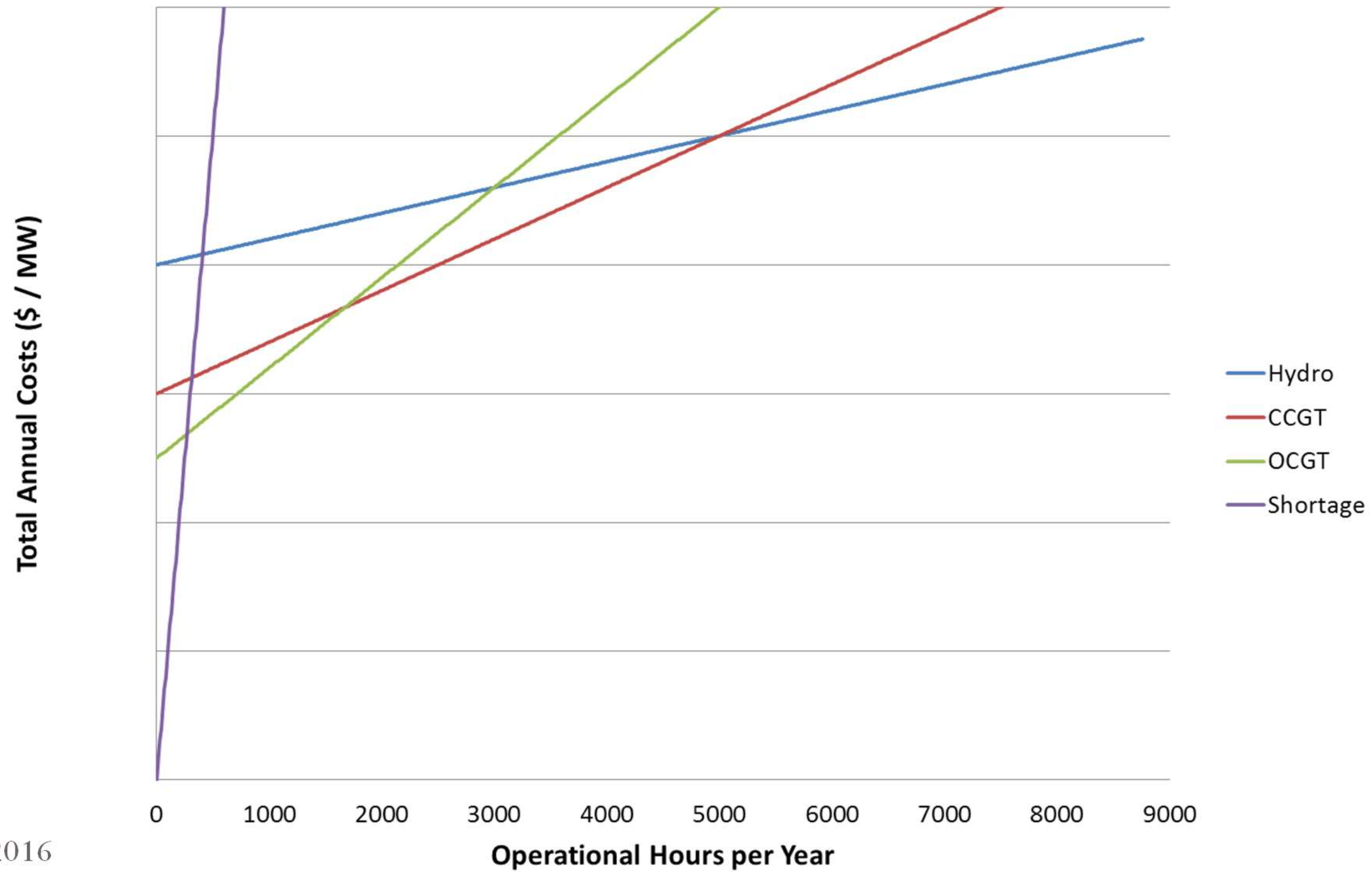
# Technologies

We will consider a set of technologies, $t \in T$ which can be used to meet demand.

| Technology | SRMC ($/MWh) | Capacity Cost ($/yr) |
|---|---|---|
| OCGT | 70 | 700,000 |
| CCGT | 50 | 1,000,000 |
| Hydro | 20 | 2,000,000 |
| Wind | 0 | 1,500,000 |
| Shortage | 5000 | 0 |

# Screening Curve

The total annual costs can be plotted as a function of utilisation.



# Investment Equilibrium

Each participant in a market is maximizing its own benefit. If we assume that no agent is able to influence the price (i.e. they are price takers), we can formulate a MOPEC, where all agents are linked by prices.

$$\max \sum_{\omega \in \Omega} q_t^{\omega} (\pi^{\omega} - c_i) h^{\omega} - C_t Q_t \qquad \forall t \in T$$

$$\text{s.t.} \quad 0 \leq q_t^{\omega} \leq Q_t$$

Simultaneously, we must ensure that supply in each scenario meets demand.

$$\sum_{t \in T} q_t^{\omega} = d^{\omega} \quad \forall \omega \in \Omega \quad [\pi^{\omega}]$$

# Investment Equilibrium

Suppose $Q_t$ is invested in technology $t$ and a set of prices and dispatch quantities $\pi^\omega, q_t^\omega$ arise from the spot market where firms offer SRMC.

If the total revenue exceeds the total costs there is incentive to increase the capacity of the technology, driving the overall expected profit to zero.

Mathematically: If $\sum_{\omega\in\Omega} q_t^\omega(\pi^\omega - c_i)h^\omega - C_t Q_t > 0$ then $Q_t$ should increase.
If $\sum_{\omega\in\Omega} q_t^\omega(\pi^\omega - c_i)h^\omega - C_t Q_t < 0$ then $Q_t$ should decrease.

The equilibrium investment quantities coincide with the social welfare maximising capacities.

In an ideal energy-only market the generators should price their offers at SRMC, and with the optimal investment choices, these should deliver the required returns.

# Constrained Technology

Things are different when there is a constraint on investment in a technology.

$$\max \sum_{\omega \in \Omega} q_t^{\omega}(\pi^{\omega} - c_i)h^{\omega} - C_t Q_t$$

$$\text{s.t.} \quad 0 \le q_t^{\omega} \le Q_t$$
$$\quad 0 \le Q_t \le \bar{Q}_t$$

If this upper limit on investment is binding at equilibrium, then that technology will make a positive return (including investment costs).

# LRMC Offering

Market participants often advocate for the need to offer above SRMC (at LRMC) in order to cover fixed costs. Long-run marginal costs can be defined as follows.

$$\text{LRMC} = \text{SRMC} + \frac{\text{FC}}{\text{hours of operation}}$$

Now if a plant's number of hours of operation (annually) can anticipated that could be offered into the market as the offer price.

This has two effects on efficiency:

- static – out of merit order dispatch;
- dynamic – inefficient investment signals.

# LRMC Offering

Consider a baseload technology in a market where all firms offer at LRMC.

Whenever that baseload plant is setting the price, it is recovering exactly the right revenue to recover its costs.

However, if there is another technology in the market (priced higher than baseload) which sets the price, baseload would over-recover its costs.

This would provide incentive for additional investment in baseload technology until no other technology will ever be dispatched (and therefore no shortage).

This equilibrium has higher total costs than with SRMC offering.

# Reserve

In the NZEM energy and reserve are co-optimised, so even in periods where there is available capacity prices can still exceed the energy offer price of the marginal generator.

This ensures that generation made available for reserve is compensated.

Note that transmission within the islands is not modelled for the purposes of reserve.

# Transmission Pricing

The purpose of Transmission Pricing is to solve the missing money problem for the transmission owner.

The transmission system is built to provide a number of benefits, namely:

- system reliability;
- market competition;
- short-run efficient dispatch;
- an option to use cheaper power.

These, combined with future focussed investment and economies of scale mean that the value of transmission is not priced appropriately in the energy market.

# Proposed TPM

The TPM proposals within the 'Second Issues Paper' greatly simplify the charging structure (compared to previous proposals).

However, the consequences of these simplifications should be carefully considered.

The proposal suggests 3 types of charge:

- connection charge;
- area-of-benefit charge; and
- residual charge.

Oddly, despite its name, the residual charge is estimated to provide the greatest revenue.

# Reaction to TPM Proposals

*I do not support Aucklanders paying an additional $78 million each year in transmission grid charges. The EA proposal would result in an average residential customer like me, paying approximately $97 extra each year, while businesses would face a $148 increase each year, schools an additional $1,577 each year and large electricity users like hospitals paying up to $22,000 extra every year.*

*The transmission pricing proposal is not fair or right, particularly given large profitable electricity generators such as Meridian and Contact and the owners of Tiwai Smelter would benefit financially by $94 million a year from the proposal, largely at the cost of Auckland and upper North Island consumers, like me. I believe transmission costs should be funded equally by all users of the electricity grid, including the electricity generators.*

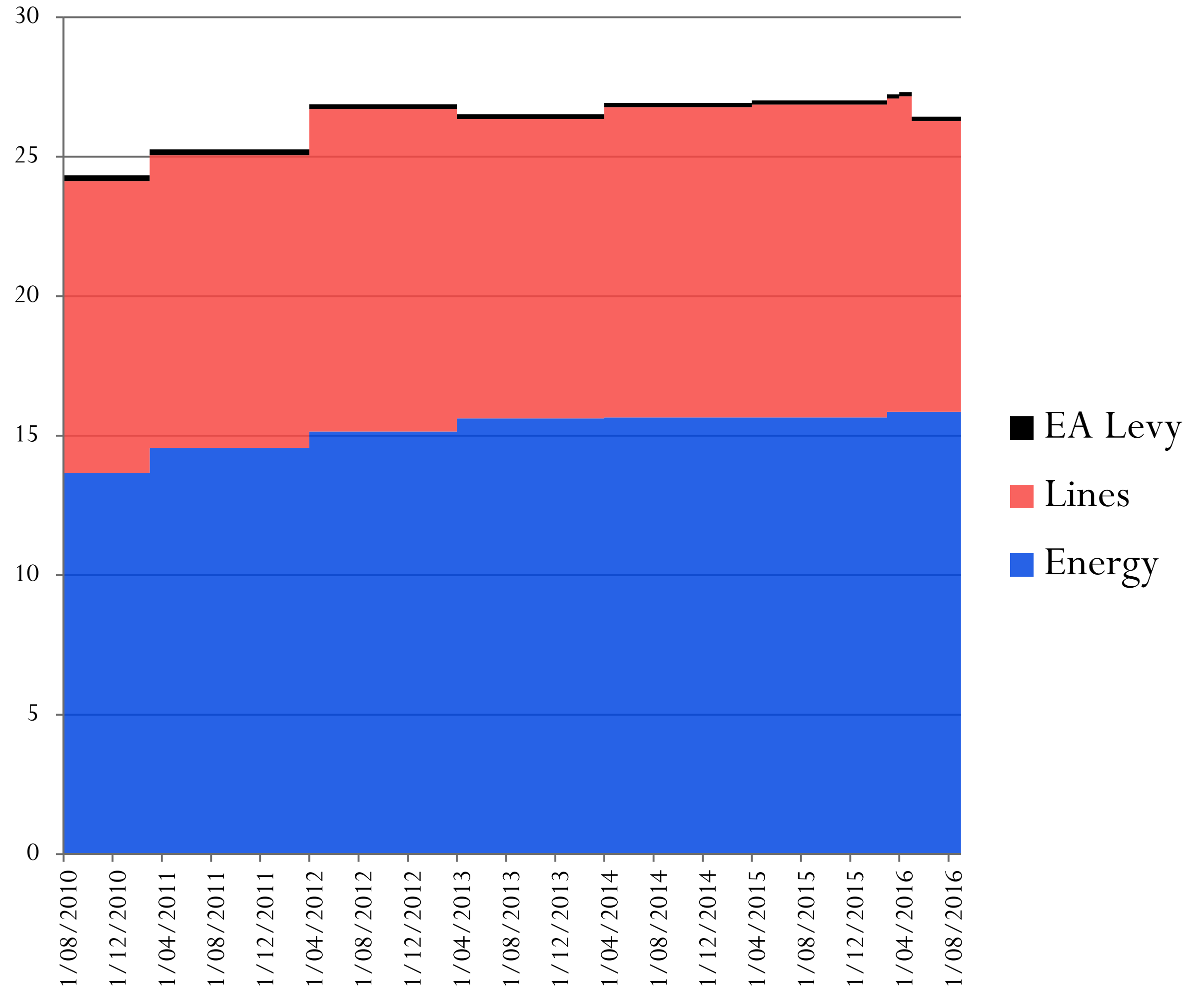
411 pro-forma submissions to EA

# Power Prices in Auckland

Over the past 6 years the energy component of a low-user's bill has climbed steadily (up 2.52% p.a.).

However, lines charges have moved up and down, with current charges lower than 6 years ago (down 0.05c/kWh).

If North Island consumers are the beneficiaries of the grid upgrades, then why are the benefits not passed on through lower retail energy prices?



# Potential Shortcomings

The proposal advocated avoiding short-term inefficiency to the detriment of peak pricing and investment pricing signals.

A number of submissions noted that RCPD is currently supressing peak load, and its removal may inefficiently bring forward the need for transmission investment.

Optimising and prudent discounting of transmission pricing is also a concern. There are two situations where one of these may be applied:

- a firm that is not efficient cannot pay its costs, or
- Transpower over-invested in the grid.

It is not in the long-term benefits of the market to have these charges subsidised through the residual charge.

# Benefits of Transmission Expansion

The area-of-benefits charge is a significant part of the proposal, However, there have been many ways proposed to compute these benefits.

A beneficiary of a line can be loosely described as either:

- a generator whose price or dispatch increases, or
- a consumer whose price decreases (or dispatchable demand increases)

due to the presence of the line.

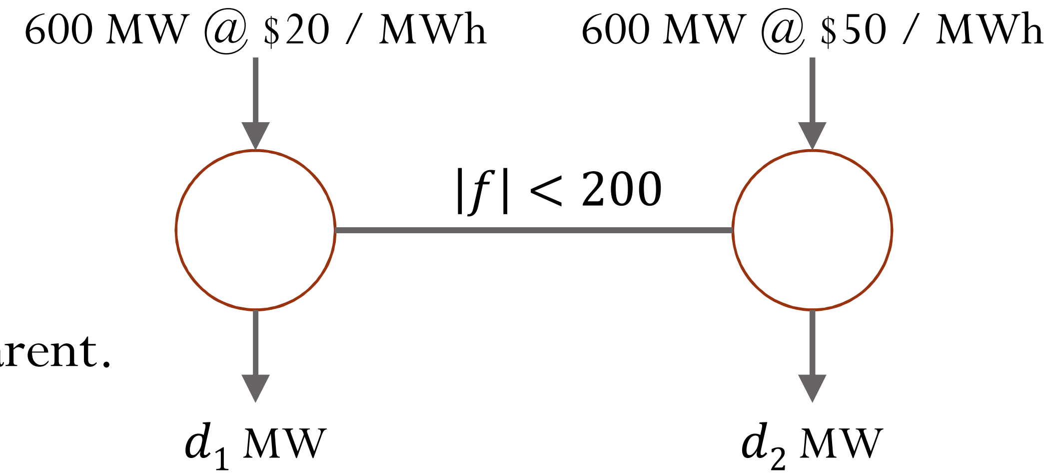
How can we capture some of these benefits to pay for the line?

# EPOC's Proposed Method

EPOC believes that both:

- the beneficiaries pay methodology, and
- the HVDC charging proposal

could be simplified and made more transparent.

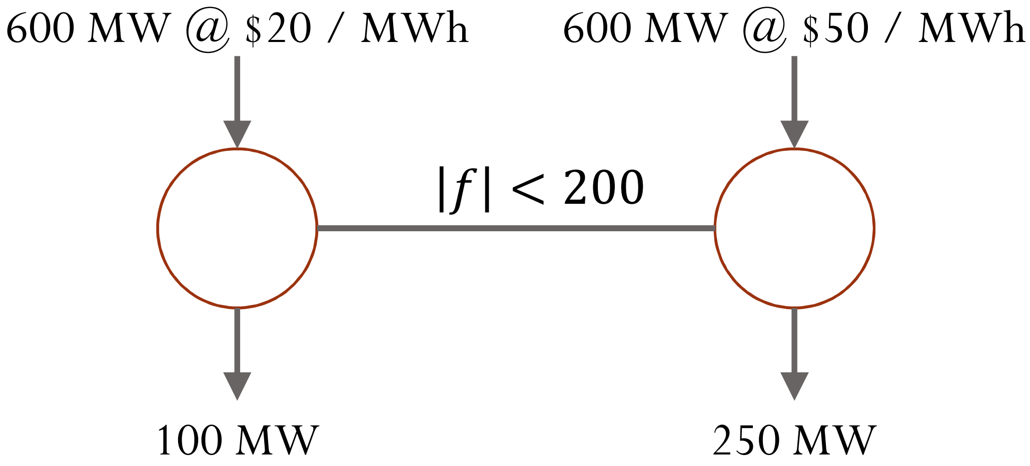


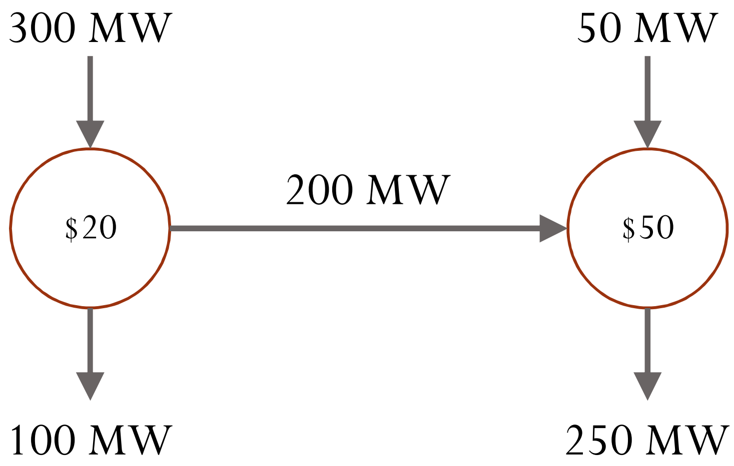

This can be achieved through charging for line flows explicitly within SPD.

$$
\begin{aligned}
\text{min} \quad & 20x_A + 50x_B + T|f_2| \\
\text{s.t.} \quad & x_A - f_1 - f_2 = d_A \qquad [\pi_A] \\
& x_B + f_1 + f_2 = d_B \qquad [\pi_B] \\
& 0 \leq x_A \leq 600 \\
& 0 \leq x_B \leq 600 \\
& -200 \leq f_1 \leq 200 \\
& U \leq f_2 \leq U
\end{aligned}
$$

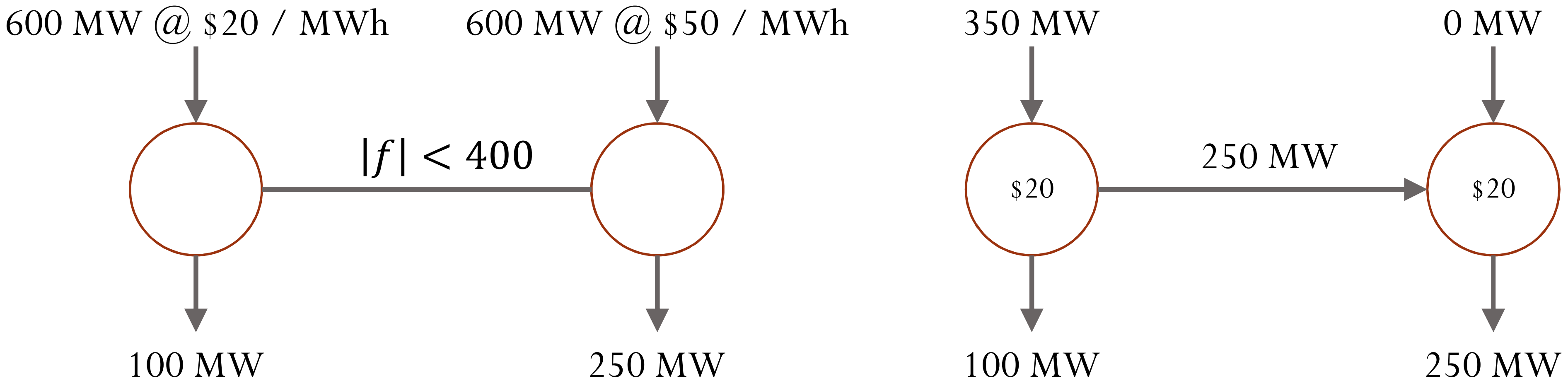
This is effectively putting a reserve margin on transmission.

# Low Demand

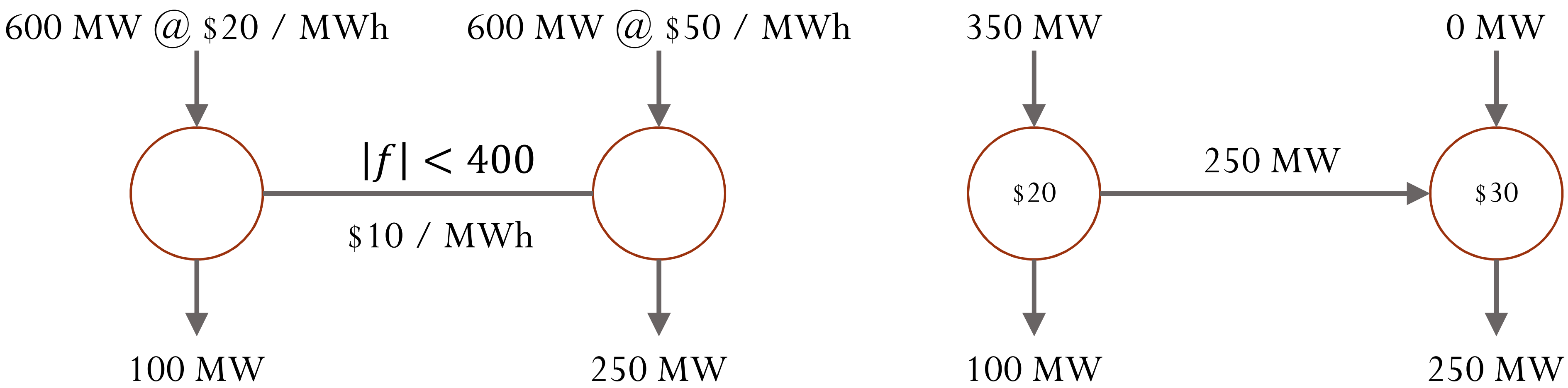

600 MW @ $20 / MWh
600 MW @ $50 / MWh
|f| < 200
100 MW
250 MW


300 MW
50 MW
$20
200 MW
$50
100 MW
250 MW

# Low Demand – Line Upgraded



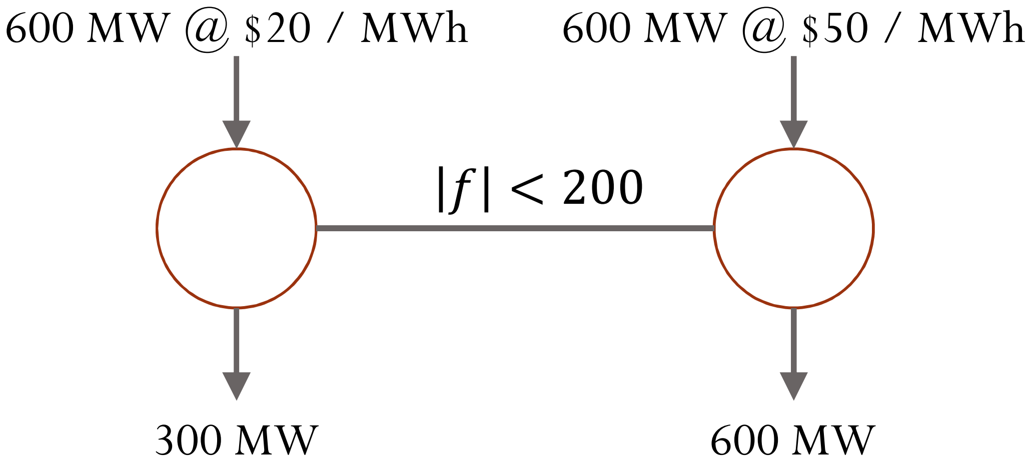
# Low Demand – Tariff Applied



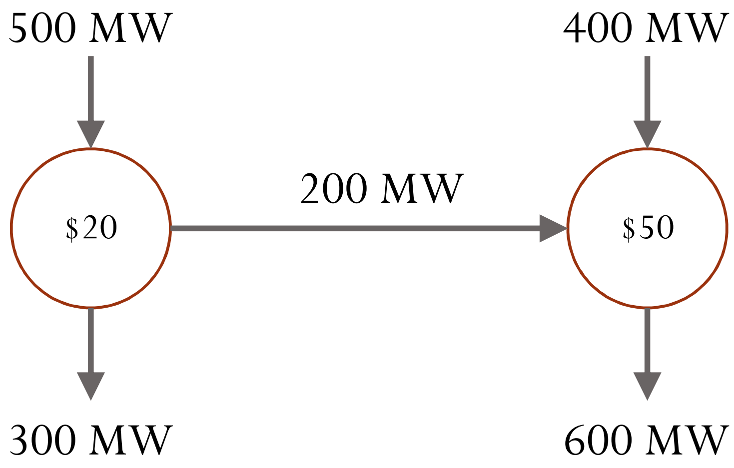
# Low Demand – Summary

| | | 200MW | 400MW | | |
|---|---|---|---|---|---|
| **Transmission Charge** | | No Charge | No Charge | $ 10 / MWh | $ 35 / MWh |
| **Prices** | Node A | $ 20 / MWh | $ 20 / MWh | $ 20 / MWh | $ 20 / MWh |
| | Node B | $ 50 / MWh | $ 20 / MWh | $ 30 / MWh | $ 50 / MWh |
| **Dispatch** | Producer (A) | 300 MW | 350 MW | 350 MW | 300 MW |
| | Producer (B) | 50 MW | 0 MW | 0 MW | 50 MW |
| **Transmission** | Flow | 200 MW | 250 MW | 250 MW | 200 MW |
| | Rents | $6000 | $0 | $2500 | $6000 |
| **Surplus** | Producer (A) | $0 | $0 | $0 | $0 |
| | Producer (B) | $0 | $0 | $0 | $0 |
| | Consumer (A) | $8000 | $8000 | $8000 | $8000 |
| | Consumer (B) | $12500 | $20000 | $17500 | $12500 |
| | Total Welfare | $26500 | $28000 | $28000 | $26500 |

# High Demand

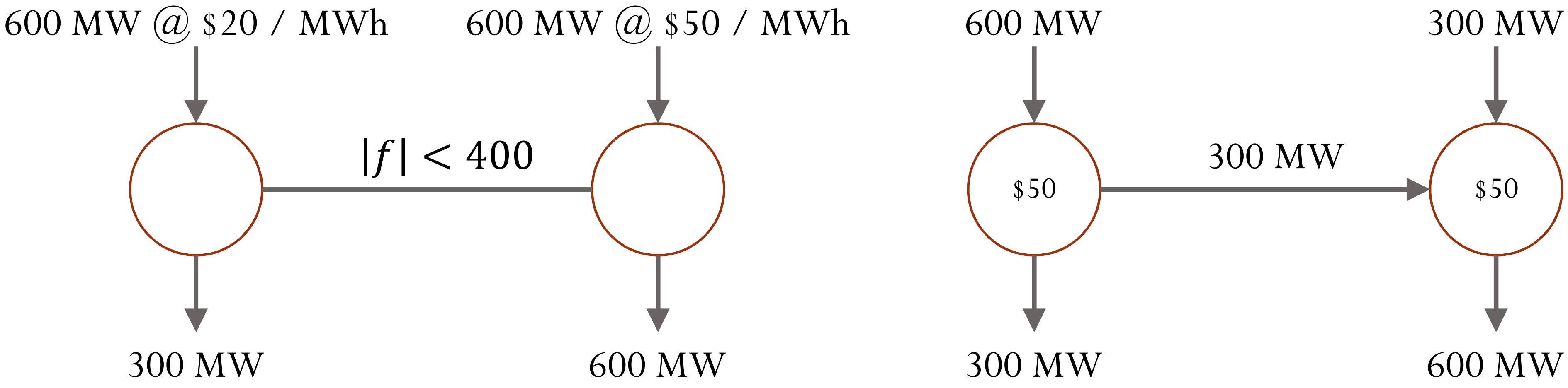


600 MW @ $20 / MWh
600 MW @ $50 / MWh
|f| < 200
300 MW
600 MW

500 MW
400 MW
$20
200 MW
$50
300 MW
600 MW

# High Demand – Line Upgraded



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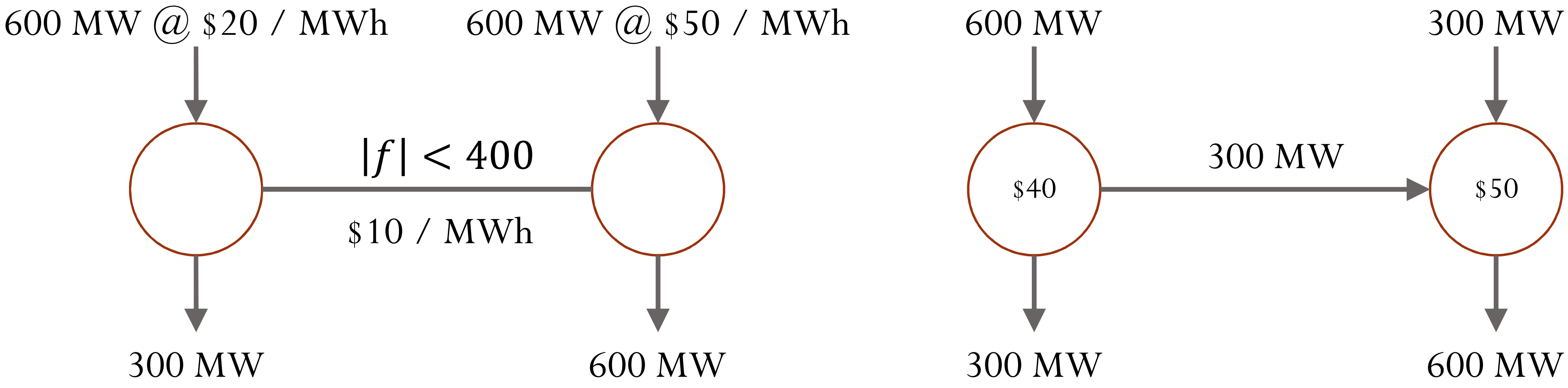

# High Demand – Summary

| | | 200MW | 400MW | | |
|---|---|---|---|---|---|
| **Transmission Charge** | | No Charge | No Charge | $ 10 / MWh | $ 35 / MWh |
| **Prices** | Node A | $ 20 / MWh | $ 50 / MWh | $ 40 / MWh | $ 20 / MWh |
| | Node B | $ 50 / MWh | $ 50 / MWh | $ 50 / MWh | $ 50 / MWh |
| **Dispatch** | Producer (A) | 500 MW | 600 MW | 600 MW | 500 MW |
| | Producer (B) | 400 MW | 300 MW | 300 MW | 400 MW |
| **Transmission** | Flow | 200 MW | 300 MW | 300 MW | 200 MW |
| | Rents | $6000 | $0 | $3000 | $6000 |
| **Surplus** | Producer (A) | $0 | $18000 | $12000 | $0 |
| | Producer (B) | $0 | $0 | $0 | $0 |
| | Consumer (A) | $24000 | $15000 | $18000 | $24000 |
| | Consumer (B) | $30000 | $30000 | $30000 | $30000 |
| | Total Welfare | $60000 | $63000 | $63000 | $60000 |