Chapter 1:

Questions for review:

1.1 Show that the (inverse) demand curve is downward sloping.

The demand curve for a price-taking individual is a function \( Q(P) \) which satisfies the first-order condition for utility maximisation:

\[
U'(Q(P)) = P
\]

By assumption \( U'(\cdot) > 0 \) and \( U''(\cdot) < 0 \). Differentiating both sides by \( P \) we find that:

\[
\frac{dQ}{dP} = \frac{1}{U''(Q(P))} < 0
\]

So the demand curve and the inverse demand curve are downward sloping.

1.2 Let’s suppose there are two products in a market. The rate of consumption of these products is denoted \( Q_A \) and \( Q_B \). The utility function for consumers of this product is:

\[
U(Q_A, Q_B) = 100 + 10Q_A + 20Q_B - Q_A^2 - 2Q_AQ_B - \frac{3}{2}Q_B^2
\]

Find the demand curves for products A and B. How does the demand curve for product A change in response to a change in the rate of the price of product B?

(Note there is a minor typo in the text which is corrected above).

The demand curves for products A and B are functions \( Q_A(P_A, P_B) \) and \( Q_B(P_A, P_B) \) which satisfy the first-order conditions:

\[
\frac{\partial U}{\partial Q_A} = P_A \quad \text{and} \quad \frac{\partial U}{\partial Q_B} = P_B
\]
Therefore we have the following simultaneous equations:

\[
\begin{align*}
10 - 2Q_A - 2Q_B &= P_A \\
20 - 2Q_A - 3Q_B &= P_B
\end{align*}
\]

Which we can solve to find the equations:

\[
\begin{align*}
Q_A &= -5 - \frac{3}{2} P_A + P_B \\
Q_B &= 10 + P_A - P_B
\end{align*}
\]

The demand for product A is increasing in the price of product B, suggesting that the two products are substitutes.

1.3 Suppose we have a monopoly provider of a particular good or service which charges a simple linear price. Suppose that the demand curve for this service is linear and takes the form:

\[
P(Q) = A - BQ
\]

Suppose that the cost of production takes the form: \(C(Q) = cQ\). Show that the monopoly profit-maximising rate of production is equal to half of the socially-efficient rate of production. Show that deadweight loss is equal to 25 per cent of the total potential economic welfare in this market. and that the deadweight loss decreases as \(P\) decreases provided that \(P > c\).

The monopoly profit-maximising rate of production is the value \(Q^M\) which maximises \(\pi(Q) = QP(Q) - C(Q)\). The first-order condition for this problem yields:

\[
Q^M = \frac{A - c}{2B}
\]

The welfare-maximising rate of production is the value \(Q^E\) which maximises \(W(Q) = U(Q) - C(Q)\), so we need to deduce \(U(Q)\).

From the first order condition for utility-maximisation we know that \(U'(Q) = P\). Since \(P = A - BQ\) we can deduce that \(U(Q) = AQ - \frac{1}{2}BQ^2 + k\) where \(k\) is an arbitrary constant.

The first-order condition for the welfare-maximisation problem yields:

\[
Q^E = \frac{A - c}{B} = 2Q^M
\]

The welfare loss relative to the welfare maximum is:

\[
\frac{W(Q^E) - W(Q^M)}{W(Q^E)} = \frac{1}{4}
\]
Using the fact that $Q = \frac{A-P}{B}$ we can write the overall social welfare as:

$$W(P) = U(Q(P)) - C(Q(P)) = AQ - \frac{1}{2}BQ^2 + k - cQ = (A - c)Q - \frac{1}{2}BQ^2 + k$$

$$W'(P) = [(A - c) - BQ]\frac{dQ}{dP} = [P - c]\frac{dQ}{dP}$$

Since $dQ/dP < 0$ it follows that the welfare is increasing (deadweight loss is smaller) as the price decreases as long as the price is above marginal cost.

1.4 Two firms produce two products, A and B, which are partial substitutes for each other. Given the price for A and B, $P_A$ and $P_B$ respectively, the rate at which customers choose to consume in the market is $Q_A(P_A, P_B)$ and $Q_B(P_A, P_B)$ respectively. Suppose that the cost of production is given by $C_A(Q_A) = c_AQ_A$ and $C_B(Q_B) = c_BQ_B$ respectively. Write down the profit of each firm as a function of the two prices in the market. Assuming that each firm chooses its price to maximise its profit while assuming that the other firm holds its price fixed, find an expression for the Bertrand-Nash equilibrium.

The profit of each firm is given by:

$$\pi_A = Q_A(P_A, P_B)P_A - c_AQ_A$$

$$\pi_B = Q_B(P_A, P_B)P_B - c_BQ_B$$

The conditions for a Bertrand-Nash equilibrium are:

$$\frac{\partial \pi_A}{\partial P_A}(P_A, P_B) = 0$$

$$\frac{\partial \pi_B}{\partial P_B}(P_A, P_B) = 0$$

Which in this case is equivalent to:

$$P_A \frac{\partial Q_A}{\partial P_A} + Q_A = c_A$$

$$P_B \frac{\partial Q_B}{\partial P_B} + Q_B = c_B$$

Chapter 2:

Questions for review:

2.1 A generator is initially producing at the rate of 100 MW at the start of a dispatch interval. It is directed by the market operator to increase its output to 500 MW by the end of the
dispatch interval (precisely 5 min later). It does so by increasing its output at a constant rate to just reach 500 MW at the end of the dispatch interval. How much electrical energy (MWh) does this generator produce in that 5 min period?

The electrical energy produced by a generator is the integral of its production as a function of time, or the area under a graph of its production as a function of time. The output in this example increases constantly from 100 MW to 500 MW over 5 minutes, so the electrical energy produced is given by the formula:

\[
\frac{1}{2} (100 + 500) \times \frac{5}{60} = 25 \text{ MWh}
\]

2.2 Why is electrical energy typically transported over long distances using high-voltage AC links? What are the pros and cons of using high voltages for transporting electricity? What are the pros and cons of DC as compared to AC links?

As noted in the text, for a given power flow, the electrical loss on a network element is inversely proportional to the square of the voltage. Therefore, electricity networks use the highest practical voltage for each part of the network.

Pros and cons of HV over LV: High voltages reduce losses (as just noted), but have other difficulties as they require much larger clearances between the lines themselves and between the lines and the ground. This requires larger, more expensive towers, larger, more expensive transformers and other equipment, and requires wider easements.

Pros and cons of DC over AC: DC links have certain advantages. The power flows are controllable; the number of conductors required may be lower; and they can be used underwater. However, they require expensive equipment at each end to convert to DC and back and a material amount of power is consumed in the conversion process. In practice, DC links tend to only be used in specialised applications.

2.3 What are the primary elements of a transmission network? What is the role played by circuit breakers? What is the role played by capacitor banks, reactors and static VAR compensators?

The primary elements of a transmission network are the transformers, poles, wires, switches, circuit breakers, capacitors and reactors, other reactive power equipment (such as SVCs), and signalling and monitoring equipment. Circuit breakers protect transmission equipment by breaking the power flow when a fault occurs. Capacitor banks, reactors and SVCs inject or remove reactive power to maintain voltage levels and to maintain the power factor on a network element close to one.

2.4 Suppose that an Open Cycle Gas Turbine (OCGT) has an efficiency of 30% (efficiency is given by the ratio of electrical energy produced to the energy in the fuel consumed), whereas a Combined Cycle Gas Turbine (CCGT) has an efficiency of 50%. Assume that the variable cost of each generator is entirely comprised of the input fuel cost. On a day
when the price of gas is $3/GJ, the variable cost of the CCGT generator is $50/MWh. What is the variable cost of the OCGT generator?

The variable cost of a generator ($/MWh) is proportional to the cost of the input fuel divided by the efficiency of the plant (the efficiency is the amount of input fuel required to produce one unit of electricity). The cost of the input fuel is the same in both cases. Therefore the variable cost of the OCGT generator divided by the variable cost of the CCGT generator is equal to the efficiency of the CCGT generator divided by the efficiency of the OCGT generator.

\[
\frac{VC_{\text{OCGT}}}{50} = \frac{0.5}{0.3}
\]

The variable cost of the OCGT generator ($/MWh) is therefore:

\[
VC_{\text{OCGT}} = \frac{5}{3} \times 50 = $83.33
\]

2.5 In market based power systems there is always a market for real power, but there is seldom a market for reactive power. Instead reactive power requirements are met through a combination of requirements on generators and loads and network assets (such as capacitors and inductors). What are the pros and cons of establishing a separate market for reactive power?

Establishing a separate market for reactive power would ensure that market participants that produce or consume reactive power are paid for doing so. In addition, it would ensure that reactive power is procured as cheaply as possible and that market participants have an incentive to innovate to develop new ways of providing reactive power where it is needed. However reactive power is not easily transported from one location to another, so the markets for reactive power tend to be very local and would likely be subject to market power issues. The overall benefit might be small.

2.6 If the wholesale electricity market worked effectively would there ever be involuntary load shedding? Why or why not?

In a functioning market customers are always able to purchase as much as they want at the prevailing price. There is never any involuntary curtailment or rationing. The same applies in an electricity market. Involuntary load shedding is only a consequence of the unwillingness or inability to allow the wholesale market to work effectively – especially the unwillingness or inability to allow the wholesale market spot price to rise or fall to market-clearing levels.

2.7 What are the implications of having large amounts of electricity storage capability (e.g., through plug-in electric vehicles) connected to the network?
The availability of large amounts of storage capability could change many aspects of the market operation. For example, it may be possible to change the mix of generation (with more use of cheaper baseload generation and less use of expensive peaking generation), and it may be possible to reduce the level of investment in networks (as less network capacity may be required at peak times). In addition, the wholesale spot price would likely be less volatile. Furthermore there may be fewer opportunities to exercise market power.

Chapter 3

Questions for review:

3.1 How does electricity market reform change the set of tasks that need to be performed in an electricity supply industry? What new tasks must be performed in a liberalised electricity market? What new problems or challenges are created by the reform process?

In any electricity industry there are certain tasks which need to be performed, including efficient operational decisions of the generation assets (and consumption assets) and efficient investment decisions in those assets. In an integrated industry these tasks are usually performed by the integrated market operator. In a liberalised electricity industry, the same tasks must be performed but the responsibility for these tasks and the incentive arrangements change. Specifically, responsibility for operational and investment decisions in generation assets is decentralised to a large number of competing generation entrepreneurs responding to price signals. Responsibility for operation and investment in network assets is placed in the hands of a network operator.

Liberalisation of the industry also introduces a number of new tasks which need to be performed including the market operator task (collecting bids and offers and computing the optimal dispatch), risk management tasks (managing inter-temporal and inter-locational price risks, including the role of the retailer), the task of price regulation of the monopoly elements (networks) and the task of coordinating generation and network investment.

3.2 What were the main objectives of electricity market reform? Has electricity market reform achieved those objectives? Are there any clear failing of electricity market reform (putting aside specific problem cases such as the experience in California)? Is there any clear benefit of electricity market reform?

The objective of electricity market reform no doubt varies somewhat from country to country, but a primary objective was to improve the efficiency of the electricity industry and/or its responsiveness to customers. Other possible objectives include enhancing flexibility, facilitating the introduction of new renewable generation, and/or reducing the political/economic power of a large integrated entity.

The experience of electricity market reform also differs somewhat from country to country. Our view is that there is some evidence that productive efficiency has increased. This has to be balanced against an increase in transactions costs (new market institutions, rule monitoring and enforcement, risk management, coordination costs) which are less
explicit in an integrated industry. There is not yet evidence of a serious failure in investment in liberalised industries, although this may be due to intervention in the market rather than the operation of the market itself. In our view it cannot be said that electricity market reform has been a failure. It remains possible that the benefits of competition on productive incentives and innovation will yield benefits in the long-term. However the experience in California is a reminder that electricity market reform can go wrong if there are conflicting policies in place, if there is an adverse sequence of events, and if the market is not allowed to operate. A liberalised market must be politically acceptable to be effective (and often must be effective to be politically acceptable).

3.3 What were the main groups of policies pursued in the liberalisation of public utility industries in the 1980s and 1990s?

The main groups of policies were: (a) corporatisation of government owned entities (i.e., placing them on the same footing as other privately-owned entities) and privatisation; (b) introduction of competition into the competitive segments of the industry; (c) focussing of regulation on the non-competitive segments (the network businesses; and (d) structural separation of the competitive and the non-competitive segments.

3.4 In the Australian NEM generators offer their output in 10 price-quantity pairs where the quantity is the amount offered at the corresponding price. The resulting offer curve is a “step function”. Would it be preferable for the offer curve to be a linear function between a set of price-quantity pairs? What are the pros and cons?

There are two ways to think about this question: (a) Which approach would give a closer representation of the “true” cost function; and (b) which approach is more convenient for the dispatch process. The derivative of a piecewise-linear function is a step function. A step offer function allows representation of a piecewise-linear cost function. A piecewise linear offer function would allow representation of a piecewise-quadratic cost function. That is something of an improvement, but arguably not much. This would come at the cost of additional complexity in the optimisation task. It is not clear there is much benefit here.

Chapter 4:

Questions for review:

4.1 What does it mean for the cost function of a generator to be non-convex? What characteristics of a generator might give rise to a non-convex cost function?

A cost function is convex if, for any two points in the range of the function, the function evaluated at a linear combination of those points is less than the same linear combination of the function evaluated at each of those points. Loosely, the cost function must be linear or increasing in slope over its range. A generator cost function could be non-convex due to, say, minimum load costs. A generator cost function might also be convex if the generator consists of a number of separate units, each of which has a minimum load level.
4.2 Under what conditions is there a monotonic-increasing relationship between the SMC (or market price) and the quantity of electricity supplied (i.e., under what conditions does higher demand lead to prices that are equal or higher)?

If the underlying generator cost functions are convex, the SMC is a convex function of the total quantity of electricity supplied.

4.3 True or false: In a general least cost dispatch with upward-sloping generator marginal cost functions, every generator always produces to the point where its marginal cost is equal to the SMC?

True. If a generator could produce more output at a marginal cost less than the SMC, the total cost of producing a given level of output could be reduced by increasing the output of this generator (and reducing the output of some other generator with a higher marginal cost).

4.4 Suppose that all customers have an inelastic demand for electricity up to a marginal value $V$ (at which point demand for electricity drops to zero). Show that the problem of total surplus maximisation is equivalent to a problem of generator cost minimisation by including a hypothetical generator with a marginal cost equal to $V$.

Each customer has a utility function given by $U(Q) = V \min(Q, L)$ where $L$ is the load. When $0 \leq Q \leq L$ this can be written as $U(Q) = VL - C(L - Q)$ where $C(Q) = VQ$. Since $VL$ is constant, the problem of surplus maximisation reduces to a problem of cost minimisation, with the addition of a generator with a capacity $L$ and a marginal cost $V$.

4.5 An energy-limited generator has a very low marginal cost of $1$/MWh. Should this generator be classified as a “baseload” generator in the merit order?

Whether or not a generator is a baseload generator depends on its marginal cost relative to other generators. In practice a generator with a low marginal cost of $1$/MWh is very likely to be a baseload generator but might not be if there is enough generation capacity with an even lower marginal cost.

4.6 True or false: In the presence of ramp rate constraints, price spikes can occur at times of off-peak demand? Explain why or why not.

True: Ramp rate constraints can be binding at any time when demand is changing rapidly (peak or off-peak). This can lead to price spikes during or before the period when the ramp rate constraints are binding.

4.7 In the presence of start-up costs, is it still correct to say that generators should be dispatched according to the merit order? Why or why not?
If we interpret merit order to refer to the order of the variable cost of generation, the answer is no. The least cost dispatch must take into account both start-up costs and the variable cost of generation. It may be efficient to dispatch generators out of merit order rather than incur start-up costs.

Chapter 5:

Questions for review:

5.1 What is a market mechanism? Why do all wholesale spot markets integrate the energy market with the physical limits of the transmission network?

A market mechanism is a voluntary process for the allocation of goods and services. AC flows cannot be directly controlled, but instead are determined by the injections and withdrawals at different points on the network. Since AC flows must be kept within physical limits, it is not possible to separate the determination of the supply and demand at each point on the network from the physical limits on the flows on the network. As a result, it is not currently possible to separate the market for electrical energy from the market for transportation of that electrical energy (at least over an AC network). Instead they are integrated in a smart market process.

5.2 True or false: A price-taking generator will submit an offer curve which matches its short-run marginal cost curve?

True: Provided certain conditions are satisfied (such as no binding ramp rates, or start-up costs).

5.3 What are the arguments for and against the establishment of a day-ahead market?

The primary argument against a day-ahead market is that it is arguably unnecessary. In all commodity markets there can arise forward markets which allow trade in advance of the spot market. These forward markets can be a day ahead, week ahead or hour ahead. These markets can arise without any specific role by the system operator or market designers.

The primary argument in favour of establishing a centralised day-ahead market is that it allows for centralised control of the unit-commitment decision. This may allow for better short-term price forecasts. It may also encourage short-term trade on the forward markets which may reduce market power.

5.4 An electricity market features a price floor of $-1000/MWh. Many generators offer a proportion of their output to the market at the price floor. Is this evidence of a lack of competition in the market?

No. Many generators have a physical minimum level of output which they can economically or stably maintain. Such generators can signal to the system operator their desire to not be dispatched for an amount less than this minimum level of production by offering this proportion of their output at the price floor. This is not evidence of market power or a lack of competition.
Chapter 6:

Questions for review:

6.1 Provide a simple example to show that the addition of a new line to an existing network may result in a strict reduction in the capability of that network – that is the new set of feasible injections is a strict subset of the set of feasible injections of the original network.

This situation will arise whenever a new line is added in parallel to an existing line and where the coefficient in the power transfer distribution factor is less than the ratio of the capacity of the new line to the existing line. For example, suppose an existing line joins two points A and B. If a new line is added in parallel to the existing line that new line will take some fraction $\alpha$ of the power flow between A and B. If the capacity of the new line is less than fraction $\alpha$ of the capacity of the existing line, the overall capability of the power system will be reduced.

6.2 Find the matrix of PTDFs for the following two networks assuming that all transmission links have identical electrical impedance, and taking node 4 as the reference node.

Matrix of PTDFs for the first network:

$$
egin{align*}
1 \rightarrow 2 & \begin{pmatrix} 1/2 & -1/4 & 1/4 \\
2 \rightarrow 4 & 1/2 & 3/4 & 1/4 \\
1 \rightarrow 3 & 1/2 & 1/4 & -1/4 \\
3 \rightarrow 4 & 1/2 & 1/4 & 3/4 \\
\end{pmatrix}
\end{align*}
$$

Matrix of PTDFs for the second network:

$$
egin{align*}
1 \rightarrow 2 & \begin{pmatrix} 1/2 & -1/6 & 1/6 \\
2 \rightarrow 4 & 1/2 & 1/2 & 1/2 \\
1 \rightarrow 3 & 1/2 & 1/6 & -1/6 \\
3 \rightarrow 4 & 1/2 & 1/2 & 1/2 \\
2 \rightarrow 3 & 0 & 1/3 & -1/3 \\
\end{pmatrix}
\end{align*}
$$

How does the introduction of the new link 2-3 change the set of feasible injections? What conditions must be satisfied for this link to expand the set of feasible injections?
The new line 2-3 expands the set of feasible injections in some respects but reduces it in others. It is not possible to set out conditions under which this addition would increase the set of feasible injections (unless we drop the assumption that the new link has identical electrical characteristics).

6.3 If the loss of any single transmission circuit is a credible contingency, and if no *ex post* corrective actions are feasible, what condition must be satisfied by any transmission network in order for the transmission network to be able to carry any power flows at all under normal operation (that is, for the set of feasible injections to have any elements other than zero).

It must be the case that there are at least two independent paths between any two points on the transmission network. In other words, either each path is duplicated (i.e., two or more circuits) or the network is organised as a loop.

6.4 Under what circumstances will the addition of a small (i.e., very low capacity) line to an existing network have a small impact on the set of feasible injections?

The addition of a small (low capacity) line will only have a small impact if (a) that line is radial to the existing network or (b) if the new line has a very high electrical impedance.

Chapter 7:

*Questions for review:*

7.1 In the case of the simple 3-node, 3-link network in which the links have identical electrical characteristics, prove the result that when there is a single constraint binding, the price at the node opposite the binding link is equal to the average of the prices at the end of the binding link.

Let's take the simple 3-node, 3-link network and assume that there is a binding constraint between nodes 1 and 2 in the direction of node 2. The prices at the three nodes satisfy:

\[ P_1 = P_3 - \frac{\lambda}{3} \]
\[ P_2 = P_3 + \frac{\lambda}{3} \]

Eliminating lambda we find that:

\[ P_3 = \frac{P_1 + P_2}{2} \]

In other words, the price at the node opposite the constrained link is equal to the average of the price at the other two nodes.

7.2 In much modelling of electricity markets it is common to assume that generators have a marginal cost which is equal to some fixed value (known as the variable cost) up to the
capacity of the generator. Suppose that demand is inelastic, that each generator submits an offer curve equal to its marginal cost curve and, further, suppose that each generator has a unique variable cost. In the absence of transmission constraints, in such a market the wholesale spot price is always equal to the variable cost of some generator in the market – known as the “marginal generator”. Does this remain true when transmission constraints are binding? In other words, is it the case that the wholesale spot price at any given node is always equal to the variable cost of some generator in the market? Can it be the case that the wholesale spot price at a node might be above the variable cost of any generator in the market?

No. When transmission constraints are binding, the price of electricity at node is determined by generator marginal costs, and constraint marginal values, and power factors. For example, in the question above, if the price at node 1 and node 2 is determined by generator marginal costs at those nodes, the price at node 3 may not be equal to any generator’s marginal cost at that node.

It can be the case that the price at a node is above the marginal cost of any generator. For example, in the question above if the price at node 1 and node 3 is determined by a generator’s marginal cost, the price at node 2 will be higher than the price at the other two nodes and potentially higher than any generator’s marginal cost.

7.3 Suppose that for a sequence of nodes in the network, the value of the PTDF matrix $H_{li}$ is decreasing. Prove that, when the link $l$ is congested, the prices on that sequence of nodes is increasing. How does this relate to the “spring washer” effect?

If node $n$ is the reference node, the price at any other node is given by:

$$P_i = P_n - \lambda H_{li}$$

By inspection we can see that if the matrix row $H_{li}$ is decreasing for a sequence of nodes, the price for the same sequence of nodes is increasing. The values of the matrix row $H_{li}$ is decreasing around any loop in the network from one end of a congested link to the other. This is the so-called spring washer effect.

7.4 Compute the merchandising surplus for the simple 3-node network example section 7.4. How does the merchandising surplus vary with the capacity of the constrained transmission link?

(Note the typo in the problem – it should refer to section 7.4, not section 7.3).

The merchandising surplus for a network with one congested link is:

$$- \sum P_i Z_i = \lambda K$$

Where $K$ is the capacity of the congested link. There is no simple relationship between the merchandising surplus and the capacity of a congested link.

7.5 Can the merchandising surplus be used to reward socially-efficient transmission augmentation decisions? Specifically, if we augment the transmission network by
some amount, does the change in the merchandising surplus correspond to the change in the social welfare arising from that augmentation?

No. The constraint marginal value reflects the additional social welfare from a small change in network capacity, but a large change will change the constraint marginal value (CMV). A transmission augmentation will result in a change in social welfare which is larger than the original CMV multiplied by the change in capacity and less than the final CMV multiplied by the change in capacity.

7.6 Let’s suppose that the nodal prices in a network happen to be negative. Under optimal dispatch should the system operator seek to maximise the network losses? Why or why not?

Yes. If the nodal price at a location happens to be negative this implies there is social value in increasing consumption at that location as long as doing so does not incur additional costs. In principle this could be achieved by increasing network losses.

Chapter 8:

Questions for review:

8.1 If a DC-link entrepreneur is considering creating a new for-profit DC link in an AC network which two nodes should the entrepreneur be seeking to connect with the DC link? To what extent does the entrepreneur’s profit depend on investment decisions in the AC network?

Ignoring the cost of building the link, the entrepreneur should seek to connect the nodes with the largest price-difference-duration curve (or strictly, the area under this curve). More generally, the entrepreneur should trade-off the cost of building a longer link against price-differences.

The profit of a DC link entrepreneur depends on price differences in the AC network. These price differences could be reduced or eliminated through AC network investment. The entrepreneur’s profit therefore depends strongly on how AC investment decisions are carried out.

8.2 Let’s suppose we have a given network configuration and a corresponding set of prices and optimal dispatch. How do we know if there is some other network configuration which might yield a higher economic welfare?

As explained in section 8.2, there is some other network configuration which yields a higher economic welfare if, in that new network configuration there is a set of feasible injections which yields a higher merchandising surplus valued at the current prices.

8.3 Is it possible to design a mechanism that might reward a network service provider for changing the network configuration when it is socially beneficial to do so?

This is discussed in section 8.2.
Chapter 9:

Questions for review:

9.1 Under the assumption that demand is inelastic and is continuously distributed, show that the proportion of time a generation type is the marginal generator is decreasing in that generation types variable cost and fixed cost.

From section 9.5 we know that the proportion of time that a generator type is the marginal generator is given as:

$$\mu_i = \theta_i - \theta_{i-1}$$

where

$$\theta_i = \frac{f_{i-1} - f_i}{c_i - c_{i-1}}$$

From these equations we can see that $\mu_i$ is decreasing in both the fixed cost and the variable cost.

9.2 Assume that we have a set of $N$ generation types ranked in order of increasing variable cost. Can you provide conditions on the fixed and variable costs under which generation type $i$ is not used at all in the efficient mix of generation?

Generator type $i$ is not used at all if $\mu_i$ is less than or equal to zero. This is the case if:

$$\frac{f_{i-1} - f_i}{c_i - c_{i-1}} < \frac{f_{i-2} - f_{i-1}}{c_{i-1} - c_{i-2}}$$

9.3 What impact do ramp rate constraints have on the optimal mix of generation?

Where ramp rate constraints are potentially binding the optimal mix of generation will be somewhat different – in particular there will be value in including faster ramping generation in the mix, even if not justified by the analysis set out in this chapter.

9.4 Let’s suppose that demand is inelastic. The demand-duration curve is given by $Q = 1000 - 1000z$. Suppose that there are three different types of generation with a variable cost of $10, $20 and $50, together with load-shedding at $1000/MWh. The fixed costs of these generation types are $15, $5, and $1/MW/hour, respectively. Find the optimal mix of generation in this industry.

The fixed costs and variable costs of the generators in this industry are:

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>Load-shedding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed cost</td>
<td>15</td>
<td>5</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Variable cost</td>
<td>10</td>
<td>20</td>
<td>50</td>
<td>1000</td>
</tr>
</tbody>
</table>
The key turning points are:

\[
\theta_{LS} = \frac{1}{1000 - 50} = \frac{1}{950} \\
\theta_{A} = \frac{5 - 1}{50 - 20} = \frac{4}{30} \\
\theta_{B} = \frac{15 - 5}{20 - 10} = \frac{1}{10}
\]

So the optimal amounts of each generation type are:

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>Proportion of time (%)</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load shedding</td>
<td>0.1%</td>
<td>1.1</td>
</tr>
<tr>
<td>C</td>
<td>13.3%</td>
<td>132.3</td>
</tr>
<tr>
<td>B</td>
<td>86.6%</td>
<td>867.7</td>
</tr>
<tr>
<td>A</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

9.5 How does increasing the capacity on a network link affect the optimal mix of generation at either end of that network link?

In general, increasing the capacity on a network link has an ambiguous impact on the mix of generation at each end of the link. The precise effect depends on the pattern of load at each end of the link. In the case where there is no load present at a node, the expansion of an (exporting) link increases the likelihood of locating generation with high marginal cost (peaking generation) at that node.

Chapter 10:

Questions for review:

10.1 True or False: In a market with inelastic demand the set of generation technologies (the set of variable costs and fixed costs of adding capacity for each generation type) completely determines the shape of the price-duration curve?

This is true. Screening curve analysis shows that if we ignore complications such as network constraints, start-up costs, ramp rate constraints and so on, and assuming that there is free entry and exit of generation, the amount of each generation type will tend towards the efficient level and the entire price-duration curve will be determined by the fixed and variable costs of generation.

10.2 Not all liberalised electricity markets have price caps. Why do wholesale market price caps exist? What is their primary role?

It is not always entirely clear why price caps are imposed. They could be imposed as a transitional arrangement to protect the market from excesses during a transition from a
non-market to a market arrangement. They could also be imposed to protect against market power (although there are perhaps better, more targeted ways to control market power). In essence price caps are a recognition that extreme market outcomes are probably politically unsustainable and therefore it is necessary to protect against extreme outcomes. However, in doing so they also mute the market incentives to respond to such circumstances directly.

10.3 The analysis in this chapter has focused on the private incentives for investment in controllable generation. What are the conditions for private investment to be profitable in, say, hydro generation? Do these correspond to the socially-optimal investment conditions?

Let’s imagine a hydro generator which receives a certain volume $L$ of water over a given period of time, such as a day (the precise period of time doesn’t matter). Let’s measure this volume of water in terms of the MWh of electricity it can produce. This generator is assumed to have no marginal cost and a maximum rate of production equal to $K$ (MW). We will also assume the generator is a price taker. Each day the operator forecasts the spot price during each dispatch interval over the forthcoming day $P_t$ and chooses a corresponding production plan $Q_t$ which maximises the short-run profit:

$$
\pi(P) = \max_Q \sum_t P_t Q_t
$$

Subject to $\sum_t Q_t \leq L$ and $0 \leq Q_t \leq K$.

In the case of a hydro generator the investment decision has two dimensions – increasing the maximum rate of production $K$ (MW) and increasing the volume of water (i.e., total energy production) captured each time period $L$ (MWh). Let’s suppose that the cost of investment is $c$ per unit of capacity and $l$ per unit of energy. The overall investment decision is as follows:

$$
\max E[\pi(P)] - cK - lL
$$

Let’s suppose that in scenario $i$, which occurs with probability $p_i$, the prices over the next day are given by $P^i_t$. The full optimisation problem is:

$$
\max \left[ \sum_{i,t} p_i Q^i_t P^i_t - cK - lL \right]
$$

Subject to: $\sum_i Q^i_t \leq L$ and $0 \leq Q^i_t \leq K$.

The Lagrangian for this problem is:

$$
L = \sum_{i,t} p_i Q^i_t P^i_t - cK - lL + \sum_{i,t} p_i \lambda^i_t (K - Q^i_t) + \sum_i p_i \mu^i \left( L - \sum_t Q^i_t \right)
$$
The first order conditions are:

\[
P_i = \lambda_i + \mu_i
\]

\[
c = \sum_{i,t} p_i \lambda_i
\]

\[
l = \sum_{i,t} p_i \mu_i
\]

These socially-optimal investment conditions, also correspond to the privately-optimal investment decision.

Chapter 11:

Questions for review:

11.1 Why, in practice, is it costly to take corrective actions? What are the primary sources of the cost of taking corrective actions? (Hint: the most significant sources of the cost of taking corrective actions are where the power system does not have the ability to make the necessary changes ex post – what sorts of short-run changes in dispatch may be outside the control of the power system operator?)

It is costly to take corrective actions when there is an inability or unwillingness to make rapid changes to the state of the power system ex post. This could be due to the inability to curtail demand efficiently – reducing load by the right amount in the right location (and by the right amount for each customer). Historically power systems have not been set up to achieve voluntary reductions in load in the very short run. In addition, the physical capability of the available plant will affect the ability to take corrective actions. If it is not possible to increase production rapidly in the required amount in the short run, it is, in effect, very costly to respond to the loss of a generator.

11.2 True or False: The optimal level of preventive actions depends on a balancing of the need to reduce the cost of corrective actions; if the preventive actions for different contingencies balance out there may be no need to take preventive actions at all? Can you provide an example?

This statement is false. While it is true that the optimal level of preventive actions involves balancing with the cost of corrective actions, it is not normally the case that the preventive actions will balance out. For example, if there is a credible contingency of both the loss of a large generator and the loss of a large load (in exactly equal amounts and probabilities) there may be a need for preventive actions in an equal amount and in opposite directions. But they will not usually “cancel out” – specifically, there may be a need to maintain both rapid response generation capable of responding to the loss of a large generator and a need to maintain generation capable of reducing output rapidly in response to the loss of a large load.

11.3 In an example in the text, generation of type 2 increased its output voluntarily. This decreased the market price. Is it possible to find an example where the market price is increased? What are the conditions required?
This question refers to the example in section 11.8.1. In that case one of the generators chose to produce more than was efficient (and another less than efficient) in the steady state to be better able to respond following the contingency. In this case the contingency was the sudden increase in load of 500 MW. It should be possible to find examples where the pre-contingency market price is increased above the no-contingency steady state level). We guess that this would occur where a reduction in load is a credible contingency, and where there would be binding ramp rate constraints on the ability of some generator to ramp down.

11.4 Find an expression for the $\gamma_t$ as a function of $P_t - c_2$ (section 11.8) and hence show that the incentive to increase the ramp rate depends on both the duration of the ramp rate constraint and the price path during that constraint.

From the KKT conditions at the stop of page 228 we have the result that:

$$\gamma_t = - \sum_{i=0,...,t} \alpha_i (P_i - c_2)$$

Here $\gamma_t$ is the constraint marginal value on the ramp rate constraint. This expression shows that the incentive to increase the ramp rate depends on both the duration of the constraint and the price path during that constraint.

Chapter 12:

Questions for review:

12.1 Should the output of the largest generator be traded off with the price of balancing services?

In general the answer is yes. If the loss of a large generating unit is a credible contingency there will generally be a need to procure a “raise” frequency balancing service in an amount sufficient to cover the loss of this generating unit. However, if this balancing service becomes very expensive to acquire it will generally be preferable (from the overall market perspective) to reduce the output of the largest generating unit(s) in order to reduce the volume of raise service required.

12.2 Should the volume of FCAS procured be price-dependent?

In general the answer is yes. The previous question dealt with the case where it is possible to reduce the output of the largest generating unit(s). But even where this is not possible, as FCAS becomes more expensive a point will eventually be reached where it is socially preferable (from an overall market perspective) to expose customers to the risk of involuntary load shedding, rather than to purchase more FCAS.

Chapter 13:

Questions for review:

13.1 A price-taking generator has a cost function given by: $C(Q) = 10 + \frac{Q}{1000}$. Assume that the price is uniformly distributed between $10 and $100/MWh. If the generator has access to
a range of cap contracts with strike prices separated by $5 (i.e., strike prices $0, $5, $10, $15, etc.), how closely can the generator eliminate the price risk it faces using a portfolio of cap contracts – in other words, what is the remaining volatility in the generator’s profit function? If the gap in the strike prices reduced to $1 how much better can the generator eliminate its price risk?

This question has a typo. The first line should read: “A price-taking generator has a marginal cost function given by $C'(Q) = 10 + \frac{Q}{10}$”. This corresponds to a cost function of:

$$C(Q) = 10Q + \frac{Q^2}{20}$$

With this marginal cost function the output of the generator is price-dependent, and is given by:

$$Q(P) = 10(P - 10)$$

The profit of the generator is then:

$$\pi(P) = PQ(P) - C(Q(P)) = 10P(P - 10) - 100(P - 10) - 5(P - 10)^2 = 5(P - 10)^2$$

This can be hedged using a series of cap contracts, each with a volume of 50 MW, and strike prices $12.5, $17.5, $22.5, . . . , $97.5. The total variance of the profit function is then approximately 195.8.

If we switch to strike prices with a separation of $1, this profit can be hedged with a series of cap contracts with a volume of 10 MW and strike prices $10.5, $11.5, $12.5, and so on. The total value of the profit function is then approximately 0.33.

13.2 What is the appropriate term of the cap contract that is used to signal the need for new investment in the network (section 13.6)?

The appropriate term for the cap contract for new generation investment (section 13.6) is equal to the life of the generating plant.

Chapter 14:

Questions for review:

14.1 What is the role of the merchandising surplus in facilitating hedging of inter-locational price risks? What does the theory say about how or why the merchandising surplus should be made available to traders?

The merchandising surplus is the natural counterparty for hedging interlocational price risk in the sense that it provides a flow of funds which is exactly equal (in total) to the amount that traders require to hedge interlocational price risk.
The theory suggests that the merchandising surplus should be made available to traders and, moreover, should be made available to traders in a way that traders can use to hedge the risks they face.

14.2 What are the drawbacks of fixed-volume transmission rights when it comes to hedging interlocational price risk?

Fixed-volume transmission rights are acceptable for hedging fixed-volume transactions. But very few market participants will engage in fixed-volume transactions. Most generators and loads will have volumes which vary with time or with the market price. Such market participants cannot eliminate their risks using fixed-volume hedging instruments.

14.3 Can traders offer hedges to generators and loads that completely eliminate the risk faced by generators and loads without taking on risk on themselves?

No. There always remains some residual risk that must be borne by some market participants.

14.4 How should a trader construct a portfolio of CapFTRs in order to hedge a transaction involving a generator and a load?

The construction of a portfolio of CapFTRs is discussed in section 14.2. The construction is similar to the construction of a portfolio of cap contracts which was raised in question 13.1.

14.5 What is the role of the merchandising surplus in facilitating hedging of inter-locational price risk?

See the answer to question 14.1.

Chapter 15:

Questions for review:

15.1 Prove the result in the text, if the profit function of a generator is given by: \( \pi(P, Q) = (P - c)Q \), show that:

\[
\pi(P_1, Q_1) > \pi(P_0, Q_0) \iff (P_1 - P_0)Q_1 > (P_0 - c)(Q_0 - Q_1) \\
(P_1 - c)Q_1 > (P_0 - c)Q_0 \iff (P_1 - c)Q_1 - (P_0 - c)Q_1 > \\
(P_0 - c)Q_0 - (P_0 - c)Q_1 \iff (P_1 - P_0)Q_1 > (P_0 - c)(Q_0 - Q_1)
\]

15.2 The short-run responsiveness of customers to the wholesale price is typically very low. Does this mean that there is no economic harm from the exercise of market power in the wholesale electricity market?

Yes and no. If consumers are completely unresponsive to the wholesale spot price there is no deadweight loss associated with an increase in the spot price. However, even if
consumers are unresponsive in the short term they may be responsive to average price levels in the longer term, which could lead to deadweight loss. Even more importantly, as discussed in section 1.8.2, the harm from the exercise of market power arises from the threat to the incentives on investment by customers. The chilling effect on investment arises even if customers are perfectly inelastic in the short run.

**15.3** A large industrial electricity user is choosing where to build a large factory. It has narrowed the search down to two towns. The towns are identical in every respect except that one has a number of competing electricity generators and the other town has a single generator. The towns are connected by an electricity network. What are the factors the electricity user should take into account when making its location decision? What does this tell us about the possible harm from the exercise of generator market power?

The industrial user should take into account the size of the electricity transmission network joining the towns. If the transmission network has a lot of capacity the generator in the town with a single generator will not be able to exercise market power. If that network is small, the monopoly generator is likely to be able to exercise significant market power.

This example shows that one of the possible consequences of market power is that end-customers will make second-best location decisions – choosing to locate in regions which, even if less desirable for other reasons, are less exposed to the threat of market power.

**15.4** How do we know when a generator has exercised market power in the past? What factors would we need to look for? What information do we need? Is it enough to know that the generator has produced at a price-quantity combination above its historic marginal cost curve? Why or why not?

To determine if a generator has exercised market power we need to show that it produced at a price-quantity combination materially above its SRMC curve. This would require knowledge of the production possibilities of the generator at that time.

It is not enough to show that the generator produced at a price-quantity combination above its historic SRMC curve as it may have experienced an outage at the particularly point in time.

**15.5** Under what circumstances would a generator exercise market power by lowering the price below its SRMC curve?

A generator which is highly hedged (i.e., is hedged to a volume above its level of production) has an incentive to lower the price below its SRMC.

**15.6** In the Australian market a price cap kicks in after approximately 10 hours of pricing at the market price ceiling (which is above $13000/MWh). This price cap significantly constrains prices (to a maximum of $300/MWh) for at least several days. Faced with the threat of this price cap how do you think generators would respond when faced with multiple opportunities to raise the price to the price ceiling?

This price cap effectively places a limit on the amount of revenue that can be extracted through sequential opportunities to exercise market power. Given this cap a profit-
maximising generator will restrict itself to only the most profitable opportunities (i.e., those occasions where the quantity withdrawal is the smallest and/or the price-response is the largest).

15.7 Can you list five policy actions that mitigate market power?

1. Increase transmission network capacity/reduce transmission constraints.
2. Increase customer responsiveness to high prices.
3. Lower barriers to entry for new generation.
4. Increase the incentive and ability for generators to hedge.
5. Wholesale price caps or restrictions on bidding.

Chapter 16:

Questions for review:

16.1 True or False: A generator in a load pocket has no market power if its capacity is less than the spare (unused) capacity on the importing transmission link?

True: Even if such a generator reduced its own output to zero it could not create congestion on the importing transmission link and thereby give rise to market power in the load pocket. Such a generator could have conventional market power at other times.

16.2 Can the diagram in section 16.3 (Figure 16.3) be generalised to the case of a meshed network and a generator with production assets at three or more nodes?

Yes, the same principles still apply. A generator with assets at two or more nodes can usually shift generation around within the portfolio. This can give rise to network congestion and therefore price differences across different locations. On occasion it can be profit-maximising to shift production around across locations in this way.

16.3 Demonstrate the result in section 16.2: In a meshed network, the residual demand curve facing a generator with market power is steeper when a network constraint is binding than when there are no network constraints. Does your result depend on the location of the generator with market power?

This answer is a little too long to reproduce here.

Chapter 17:

Questions for review:

17.1 What are the strengths are weaknesses of each of the following: market share indicators, PSI and RSI, residual demand analysis, and full market modelling?
### Approach

<table>
<thead>
<tr>
<th>Approach</th>
<th>Strengths</th>
<th>Weaknesses</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Market share indicators</strong></td>
<td>Simple, easy to compute, intuitive, easily verified.</td>
<td>Can be misleading (even generators with small market share can have material market power at times). Ignore differences in the variable cost of different generation. Does not easily handle transmission constraints. Market shares vary over time, giving rise to aggregation issues.</td>
</tr>
<tr>
<td><strong>PSI and RSI</strong></td>
<td>Relatively simple and easy to compute. Captures the observation that even small generators can have market power at times.</td>
<td>Do not easily handle transmission constraints. PSI and RSI vary over time, giving rise to aggregation issues.</td>
</tr>
<tr>
<td><strong>Residual demand analysis</strong></td>
<td>More closely based in economic theory. Takes into account differences in the costs of generation.</td>
<td>Residual demand curve varies widely over time giving rise to aggregation issues. Transmission constraints have to be assessed on a case-by-case basis.</td>
</tr>
<tr>
<td><strong>Full market modelling</strong></td>
<td>Can, in principle, take into account a range of different market demand, supply and network conditions.</td>
<td>Can be non-transparent (“black box”). This approach requires a very large number of assumptions. There can be a large number of Nash equilibria giving rise to questions about how to select or aggregate. Questions of how to aggregate a range of different possible outcomes still arise.</td>
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#### 17.2 If there is a problem with market power, what are the pros and cons of imposing a market price cap?

The strength of a market price cap is that it is a fairly simple instrument that typically is fairly easy to impose. On the other hand, the problem with a price cap is that it is a blunt instrument which does not directly target the exercise of market power and it may, in fact, stifle the incentives for investment which are needed to erode market power over time.

#### 17.3 If a generator reduces the amount it offers to the market and the wholesale price increases significantly, does this mean the generator is exercising market power – why or why not?

No it does not. A generator may choose to reduce its output for a variety of reasons – for example if there is an outage, or if there is an increase in the price of an input fuel. To show that a generator is exercising market power we would have to show that these other explanations are not relevant in the circumstances.
Chapter 18:

Questions for review:

18.1 Is it the case that, in a radial network with a single load node, the optimal level of network capacity on any given network element is equal to the generation capacity “behind” that network element? Why or why not?

This is true. The reason is that in an optimally-configured network (and assuming generation is perfectly reliable), at a node which has no load, the total transmission capacity away from that node should not exceed the generation capacity at that node. If it was larger there would be a waste (excess) of transmission capacity. If it was smaller, some of the generation capacity would never be able to be exported.

18.2 Is it possible to use the merchandising surplus as a measure of the economic benefit from a network augmentation? Should the network business be allowed to augment the network if doing so increases the merchandising surplus by more than the cost of the augmentation?

No. The merchandising surplus is the product of the constraint marginal value and the capacity on the congested link. The constraint marginal value is a signal of the economic benefit from a small network augmentation, but a large network augmentation will change the constraint marginal value, possibly reducing the merchandising surplus. A socially-efficient investment which augments the network capacity may reduce the merchandising surplus, so it is not possible to design an incentive scheme for network investment based on the merchandising surplus.

18.3 What are the conditions for efficient investment in a DC link? When should a DC link be augmented?

Investment in a (price-taking) DC link is efficient if the area under the price-difference-duration curve exceeds the unit cost of the investment. A DC-link should be augmented by a small amount if the expected price differences across the ends of the link exceed the unit cost of the investment.

18.4 If demand is dropping, so that there is excess capacity on the network, would you expect the revenue from nodal price differences (the merchandising surplus) to be equal to the long-run marginal cost of network expansion? Why or why not?

No. If there is excess capacity on the network, network congestion is likely to be rare (less common than the long-term average) and the merchandising surplus is likely to be lower than the long-term average, and below the long-run marginal cost of network expansion.

Chapter 19:

Questions for review:

19.1 The discussion in this chapter has focused on the impact of mis-pricing on scheduled generators (which must submit an offer curve to the dispatch engine and which must
follow dispatch instructions). What is the impact of mis-pricing on smaller generators that are unscheduled?

Non-scheduled generators do not have to submit offer curves and do not receive dispatch instructions. Instead they simply react to the market price. Mis-pricing sends these generators the wrong signals, resulting in inefficient levels of production from these generators. The problems of inefficiency of dispatch and negative settlement residues still arise, but the problem of disorderly bidding does not arise, since these generators do not submit bids.

19.2 In the Australian NEM mis-pricing of generators gives rise to what is known as “disorderly bidding”. Can you describe what disorderly bidding looks like and explain how it is different from the exercise of market power?

Disorderly bidding involves generators distorting their offer curve in order to either increase or decrease the amount for which they are dispatched. For generators which are constrained off, they will typically distort their offer curve by offering at a low price such as the market price floor. For generators which are constrained on, this will typically involve offering at a high price or pretending to be unavailable.

Disorderly bidding is different to market power in that it will arise even if there are a large number of competing generators. Disorderly bidding has nothing to do with a lack of competition.

19.3 We have seen that regional pricing (in the absence of constrained-on/constrained-off payments) results in inefficient operational decisions, negative merchandising surplus and negative settlement residues, and inefficient investment decisions. Can you think of an argument in its favour?

There are no good arguments in favour of regional pricing without constrained on/off payments. We could argue that it is simple, that it is politically acceptable, or that it is consistent with an approach which seeks to overbuild the transmission network in each region so as to minimise constraints.

19.4 Do generators have an incentive to locate at a node that is routinely constrained off? Why or why not?

Possibly yes. Even without constrained-off payments, a generator may prefer to locate at a node which is occasionally constrained-off, even if that means only being able to be dispatched for some fraction of its output at such times. The threat of being constrained off is not necessarily a deterrent to investment. Moreover, if there are constrained-off payments a generator may have a strong incentive to locate in a location that is periodically constrained off, in order to receive a share of those payments.

19.5 Does the use of constrained-on/constrained-off payments solve the problem of inefficient operational decisions and inefficient investment decisions? Why or why not?

Constrained-on/off payments solve the problem of inefficient operational decisions but not inefficient investment decisions. Constrained-on/off payments ensure that generators
produce at the efficient level at times of network constraints. But constrained-on/off payments can distort the investment decision as suggested in question 19.4.

19.6 What problems arise when we pay a different price to generators and loads at the same location?

In such circumstances generators and loads at the same location have an incentive to not transact in the centralised market but to enter into side-deals and side-arrangements.

19.7 What is the effect of nodal pricing for generators/regional pricing for consumers on generator market power?

A full answer to this is beyond the scope of this question, but we can observe that regional pricing for consumers mutes or eliminates the incentives of customers to respond to the exercise of market power, which results in greater incentives to exercise market power by generators.

Chapter 20:
Questions for review:

20.1 What are the major pros and cons of nodal pricing at the distribution network level?

As the role of consumers change, and consumers become more active in their production and consumption of electricity (the “prosumer”), it will become more important that consumers face the right price signals to make the right decisions about the usage of and investment in a range of devices and appliances. Nodal pricing is currently the only known price mechanism which determines the correct dynamic price signals. It is likely that some form of nodal pricing of distribution networks will be required in the future.

At the same time, nodal pricing is both complex and may allow for the exercise of market power. Consideration will need to be given to the level of granularity of the prices (in both time and space). For example, should the nodal pricing be extended down to the household level, the street transformer level, the feeder level, or the zone substation level? In addition, there are important questions about how nodal pricing at the distribution level will interact with nodal pricing at the transmission network level.

20.2 Does the presence of time-averaged distribution network charges result in inefficient decisions to invest in local (embedded) generation? Do small customers have too much incentive to invest in solar PV generation?

Almost certainly the time-averaging of distribution network charges will have some impact on the usage of and investment in certain devices and appliances such as solar PV. In particular, time-averaging favours generation which is constant over time (such as solar) over generation which can respond dynamically at times of high prices.

It is not possible to say whether or not small customers have too much incentive to invest in solar PV, but other things equal, the time-averaging of distribution charges would tend in that direction.
20.3 Is it possible that time-averaging of distribution network charges may threaten the viability of the distribution network itself? Why or why not?

Yes, it is possible. It is possible that time-averaging of network charges may induce investment in alternative technology (such as solar PV and battery storage). This investment may, in principle, eventually threaten the viability of the distribution business itself. It is possible that there is no time-averaged charge which would allow the distribution business to cover its costs.

20.4 What are the pros and cons of time-of-use pricing, critical-peak pricing, and capacity-based charging?

Time of use pricing may help customers to get used to the idea of shifting their electricity consumption around in time. However static time-of-use pricing cannot send the dynamic price signals of network congestion which are almost certainly required.

Critical-peak pricing does a better job of signalling dynamic network congestion (or high wholesale spot prices). But restrictions on the level of the critical-peak price or the number of times the critical peak can be called in a year limit the extent to which this approach can expose the customer to the correct price signals.

Capacity-based charging helps the customer get used to the idea that they should pay attention to their peak capacity. However it also creates incentives to economise at times when the customer is approach peak capacity but there remains spare capacity on the network. The primary weakness of this approach is that price peak demand does not necessarily correspond to network peak demand.

20.5 Suppose that a new technology is developed which allows customers to obtain all their electricity needs without connection to the electricity grid. Should disconnection be allowed? Under what circumstances?

We would like customers to make a socially-efficient decision to disconnect. This means that the revenue savings they forego by disconnecting should reflect the social cost savings from no longer having to serve that customer. If the social cost savings is small, the revenue saving if any should also be small. This may require the use of, say, a disconnection or termination fee.