Submission to the

Victorian Renewable Energy Auction Scheme

Consultation Paper

Melbourne Energy Institute
September 2016

Introduction

The Melbourne Energy Institute (Institute) welcomes the opportunity to provide comment on the *Victorian Renewable Energy Auction Scheme Consultation Paper*.

The Institute brings together the work of over 150 researchers, across seven faculties at The University of Melbourne , providing international leadership in energy research and delivering solutions to meet our future energy needs. By bringing together discipline-based research strengths and by engaging with stakeholders outside the University, the Institute offers the critical capacity to rethink the way we generate, deliver and use energy.

The Institute presents research opportunities in bioenergy, solar, wind, geothermal, nuclear, fuel cells and carbon capture and storage. It also engages in energy efficiency for urban planning, architecture, transport and distributed systems, and reliable energy transmission. Economic and policy questions constitute a significant plank of the Institutes research program and include: market regulation and demand; carbon trading; energy system modelling; climate change feed backs; and social justice implications of energy policy.

We thank you for the opportunity to provide comment to this process and please do not hesitate to contact us at the Melbourne Energy Institute on 03 8344 3519.

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1 Scheme structure

1.1 Target definition

A clear objective of this scheme is to that *'sufficient certainty is provided to industry'* and ensure an *'adequate pipeline of projects is available to meet the targets'*. In the public consultation, the target was described as *'Rock Solid'*. The Institute strongly supports this aspect of the scheme, and agree it particularly critical, given a major aim is to counter the uncertainty surrounding the Federal Scheme.

However, other aspects of Consultation Paper seem in contradiction to this. The Department also argued a ''need to maintain some flexibility for the Government to adjust the scheme where the market changes significantly.' This is incompatible with providing certainty to the industry. Indeed it was a significant *'market change'* (a dramatic and unexpected reduction in demand) that ultimately resulted in the Federal target being reduced, creating substantial uncertainty for the industry.

While the Department provided a qualified target of '*up to*' 5,400 megawatts (MW), the Institute recommends an explicit target, ideally in MW of MWh, to provide the certainty that this scheme aims to achieve. This could be provided in annual figures, as is down in the Federal scheme.

1.2 Treatment of Large-Scale Generation Certificates

Large-Scale Generation Certificates are currently priced at levels well above what would be expected for projects to reach financial closure. There is clearly an issue with securing finance for both merchant project (buying and selling on the spot markets) or projects with bundled power purchase agreements (PPA, a contract that incorporate both certificates and wholesale energy value).

We do not have a strong view on how certificates are treated. Contracts for Difference or Feed-in Tariffs can be appropriately designed for cases where the Government takes certificates or project developers take certificate. In one case, the contract payments or counter-payments would be bench-marked against the certificate spot prices, and in the other case revenue would be sort from sale of certificates on the spot market. In both of these cases, revenue flow would be identical in theory, with albeit with different parties responsible for the sale of certificates.

2 Payment structure

The Department is proposing to award 'Contracts-for-Difference' (CfD) to achieve the objectives of the scheme. The Institute supports the use of CfD's and agree that these contracts represent an appropriate mechanism to deliver certainty to the industry, and entail sufficent flexibility to facilitate cost effective integration of renewable energy.

The Department also noted the desire to *'ensure projects continue to receive price signals from the NEM,'* and ensure that the *'scheme does not distort the NEM significantly by incentivising generators to dispatch electricity even where NEM prices are negative in a given time period'*. The Institute agrees with this approach, however we would point at that this objective is at odds with other objectives. In particularly, ensuring this partially comes at the expense of provide certainty and reducing the difficulty in securing finance.

Reference price and location signals

The Department has proposed using a monthly average reference price as the basis for calculating payments made, and suggest that this will It is not clear how price appropriate price signals can be signalled through a monthly average, or how this might improve the *'correleation between generation under the scheme and market demand'*. This is particularly true of daily cycles which would be invisable in a monthly average approach. The Institute disagrees with this approach.

The half-hourly price on the other hand *does* provide clear and appropriate price signals. We can not foresee any reason preventing contract positions being settled using half hourly prices and generation or even 5 minute prices and generation, should the market evolve that way[1]. This would ensure projects are appropriately incentivised by underlying market signals and dynamics, on appropriate timescales.

We do agree with the Departments proposed approach for location price signals. The approach of taking Transmission Loss Factors into account is consistent with the procedures and incentives in the National Electricity Market. However, we would point that the value of incorporating TLFs is less valuable and somewhat diminished if the reference price was determined on a monthly basis.

2.1 Proposed Contracts-for-Difference Structure

While broadly agreeing with the CfD approach, we argue that the scheme as currently described, does *not* enable cost effective integration or deliver on the objectives to 'minimise scheme costs'. As described in the Consultation Paper:

> *'Projects offering the lowest strike price (as well as meeting other criteria) would then be awarded funding under the scheme in the form of a feed-in-tariff for the difference between the strike price and a reference price for electricity sold in the wholesale National Electricity Market (NEM) (as well as potentially the sale of LGCs).'*

This arrangement is illustrated in Figure 1. Whilts this approach provides a secure revenue stream, and thus lower financing cost, it does not ensure lowest cost to the Government nor provide appropriate incentives for cost efficient integration into the NEM.

Firstly, the lowest strike price *does not* equate to the lowest *cost* for State. The South Australian electricity market allows for a useful illustration of this critical difference. For the 2015-16 financial year, the *value* of wind generation in the South Australian electricity market was approximately $47 per MWh. This compares to the total volume weighted price of $68/MWh, while solar PV generation would have worth approximately $70-80 per MWh. The table below show the theoretical costs of two projects in South Australian region that deliver the same amount of energy, albeit at different times, and thus values.

[1]The implications of AEMC's current '5 minute settlement' rule change request should be considered when entering into any contracts (AEMC, *Five Minute Settlement: Consultation paper*)

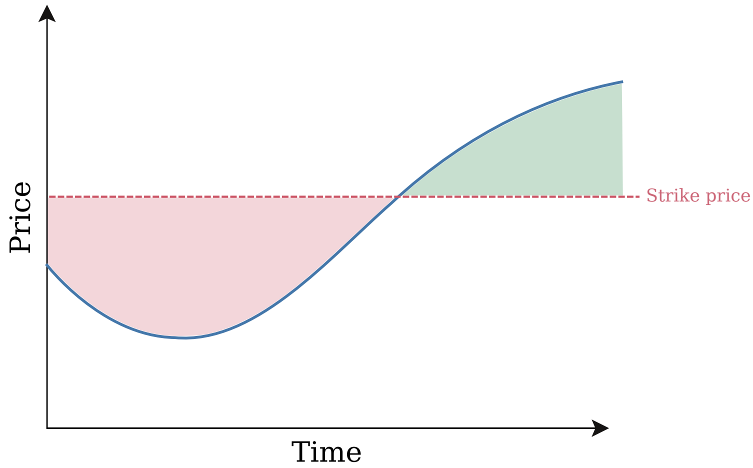

Figure 1: Illustratrative diagram of a Contract-for-Difference (CfD). When the market price is below the 'strike price', the difference is paid from the Government to the Generator (shaded red region). When the market price is above the 'strike price' the difference is paid from the generator to the Government (shaded green region). As can be seen, depending on the market price, payments can flow both ways.

In this illustrative example the theoretical *costs* of the scheme are represented by the difference between the strike price and the wholesale market value. In this case the *costs* of the solar project are below the *cost* of the wind scheme, yet the *strike price* is higher.

Table 1: Theoretical costs for two different projects in South Australia

	Wholesale Market Value ($/MWh)	Strike Price ($/MWh)	Difference ($/MWh)
Solar	$80	$110	$30
Wind	$47	$80	$33

For the 2015-16 financial year, the difference between the value of wind and solar in Victoria was in the range of $13-$18/MWh. This is currently less than in South Australia, however it would be expected to increase as wind penetration continues to grow, noting that South Australia currently has a penetration renewable energy in line with Victoria's 2025 target.

This flat CfD approach at best obscures and at worst distorts these incentives provided by the NEM. Project developers are effectively shielded from price signals generated by the NEM. This would encourage continued addition of the cheapest source of energy, even if that energy had reduced (or even no) value.

This in turn creates a second problem by inappropriately allocating risk to the Government and exposing the government to the risk of cost blowouts. The difference between the 'strike price' (lowest cost project) and the market value of a particular technology would be expected to increase as more of that technology was added to the grid. This results from the 'merit order effect' and the reality that wind generation and solar generation is generally correlated.

We strongly disagree with using the lowest *strike price* as the main metric for assessing projects. An approach that uses the *strike price* as a measure of project cost-effectiveness *inappropriately* allocates risks between the Government and project proponents. We believe this approach will not deliver cost effective integration of renewable energy, as the project developers are not appropriately exposed to market signals. Further, this approach does not ensure the lowest cost to the Government.

2.2 Alternative payment structures

Structured CfDs

The basic payment structure suggested by the Department could be slightly modified to provide better alignment with market signals, by offering contracts aligned with different coverage periods. A straight forward approach would be to utilise coverage periods that are aligned with hedging strategies that already exist for wholesale market participants. Currently, three types hedging contracts are commonly traded (see the AEMC report[2] and Productivity Commisions report[3] for further details and discussion):

- **Base load futures**, which cover a full 24 hour period on each day over a specified calendar quarter.
- **Peak load futures** which only cover the period from 7:00am to 10:00pm on working weekdays in a quarter.
- **$300 cap futures**: Allow a retailer to manage the risk of high spot prices in a similar manner to an OTC cap with a strike price of $300/MWh.

Having CfD categories based on these three categories would allow better integration with the existing derivatives markets and wholesale market practices (see Figure 2). As the market evolves, future CfD would be able to take into account changing market conditions and reward projects appropriately. Coincidentally, these three contract coverage periods could broadly align with wind, solar and storage projects respectively[4].

It should be noted that awarding projects based on *price* still suffers some of the same shortfalls, as previously identified. For example anti-correlated wind farms, that may have greater cost but also much greater value, are not appropriately awarded.

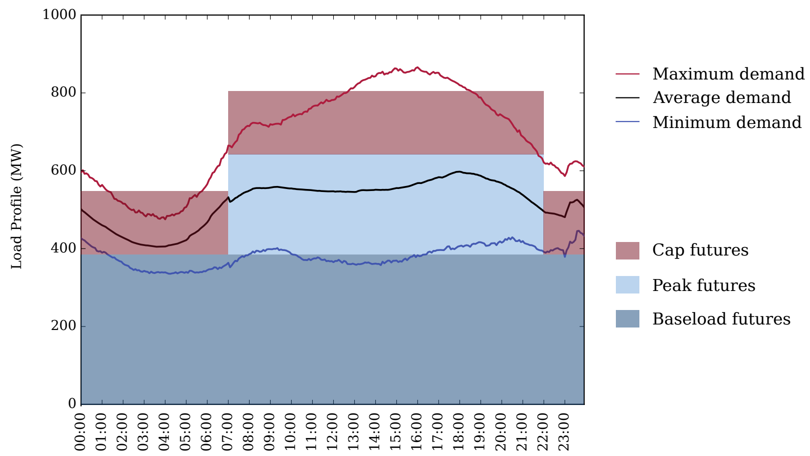

Figure 2: This figure illustrates the standard hedging products used by generators and retailers to manage price risks in the the wholesale electricity market. The contract coverage periods for peak load and base load could be useful benchmarks to base CfDs structures on

[2] AEMC, *NEM financial market resilience: Issues Paper*; Productivity Commission, *Electricity Network Regulatory Frameworks*.

[3] Productivity Commission, *Electricity Network Regulatory Frameworks*, Appendix C.

[4] While the scheme does not explicitly support storage projects, renewable projects maybe able to cost-effectively integrate storage into their projects

Fixed payment contracts

The Consultation Paper raises the prospect of fixed payment contracts, irrespective of the level of generation output. As described in the paper, this approach would not decrease the exposure to price risk. Indeed it is not actual clear that any revenue stream is actually captured by a CfD like structure.

This approach is akin to a premium feed-in tariff, albeit paid on a fixed basis, rather than output of MWh. Under this approach, the exposure to price risk would facilitate better exposure to the NEM price signals, and thus better integration of generation. However, approach also locks in a fixed payment for scheme, regardless of price moments in the wholesale electricity market or generator output. If prices in the wholesale market were to dramatically increase through the withdrawal of a large coal generator or introduction of a form of carbon price, scheme payments would not decrease (as they would in a CfD structure), and project developers may recieve windfall profits.

An alternative payment structure to consider is a fixed *volume* based contract for difference, would effectively operate as a premium Feed-in Tariff. This approach combines some elements of the previous fixed cost structure, allowing *costs* to be minimised, while providing incentives for project developers to align with wholesale market price signals signals as they evolve over time. Figure 3 illustrates who this approach might operate.

While this does expose project developers to wholesale market price risk, we think this provides an improved allocation of risks between Government and developers, and sufficient flexibility to facilitate cost effective integration of renewable energy. Under this approach, the price signals and electricity market risks are taken on by the project developers. This should encourage generation in the lowest cost location and with the best value generation profile, as price signals evolve over time and system dynamics change.

Projects financed this may still have some difficulty financing projects, since *some* of the revenue is subject to wholesale price. However, the long term revenue secured from the Government contract would not present the same risk, in stark comparison to current LGC price risk. In effect, the renewable energy certificate price risk is taken by the Government, which is one of the major risks this scheme is aiming to mitigate. We think this more *'appropriately allocate[s] risk between the Government and project proponents'*.

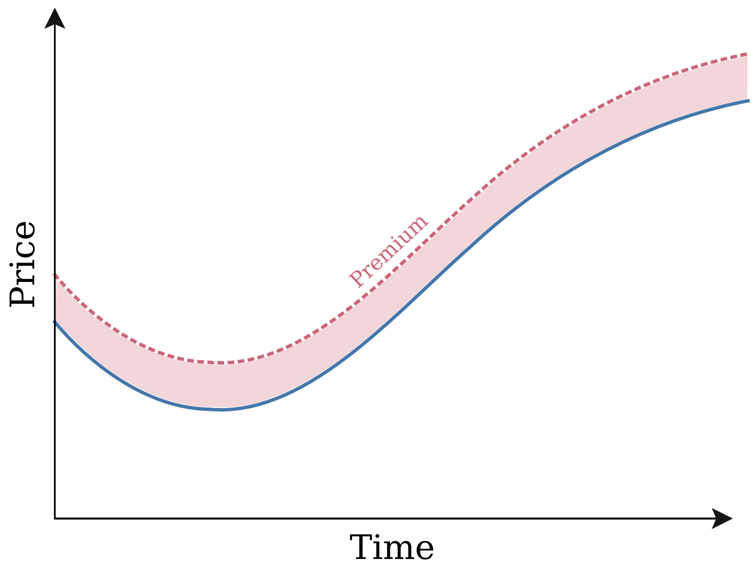

Figure 3: Illustratrative diagram of a Premium Feed-in Tarrif (FiT). The premium (shaded red regions) is paid from the Government to the Generator at all times. Payments only occur one way, and developers may receive windfall profits if wholesale prices dramatically increase.

Premium CfD

To alleviate this price risk, the premium FiT could be hybridised with a CfD. This 'premium-CfD' that could effectively provide some exposure to wholesale market prices, albeit with a cap price and floor, to help minimise both risks and costs. This is illustrates in 4.

This has two major benefits. Firstly, it would improve certainty for project developers and secondly, should wholesale market prices dramatically increase contract payments would be reduced (and would perhaps be receipts). This does however become slightly more administratively complex. To be effective, the cap and floor would ideally be on similar time-periods as discussed above in the Structured CfD section.

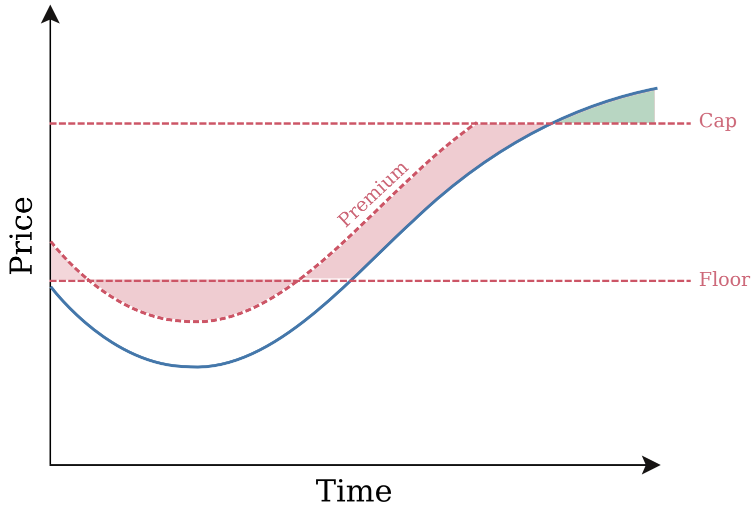

Figure 4: Illustratrative diagram of a Premium CfD. When the market price is below the 'floor price', the difference is paid from the Government to the Generator. This ensures a minimum guaranteed revenue. Between the floor and cap price, the generator is exposed to the market price, but also receives a premium. When the market price is above the 'cap price' the difference is paid from the generator to the Government (shaded green region). As with the basic CfD, depending on the market price, payments can flow both ways. Importantly, this design both provides some guarantee of price (the floor price), exposes the developer to some market signal (premium), and prevents wind fall profits (above the cap price).

2.3 Comparing the three approaches: Risk allocation and market integration

Ultimately, there is a trade off between market certainty (risk allocation), cost efficient market integration and cost. Figure 5 over page illustrates how the risk and market integration varies with the three proposed approaches.

The premium CfD provides both the exposure to market prices required for cost effective integration into the electricity market and a degree of security that should lower both financing and scheme costs. However, this scheme would be more administratively complex.

The simpler premium FiT provides more appropriate more appropriate risk allocation for effective market integration, but comes at the cost of certainty and financing costs. In addition, the Premium-FiT doesn't provide flexibility should a Federal mechanism (e.g. baseline and credit scheme) come into effect, or withdrawals occur which increase prices and create the potential for windfall profits.

The basic CfD provides the best certainty for developers, albeit at a cost to the Government and to the detriment of effective system integration. At a minimum, the CfD could be slightly structured around existing standard contract periods (e.g. baseload and peak load). Alternatively, the CfD could cover only a fraction of the generation (say 80%), leaving some the remaining generation fully exposed to the market to incentivise efficient market integration. Both the CfD structures discussed are more suitable and flexible for integration for any Federal policies that come into effect.

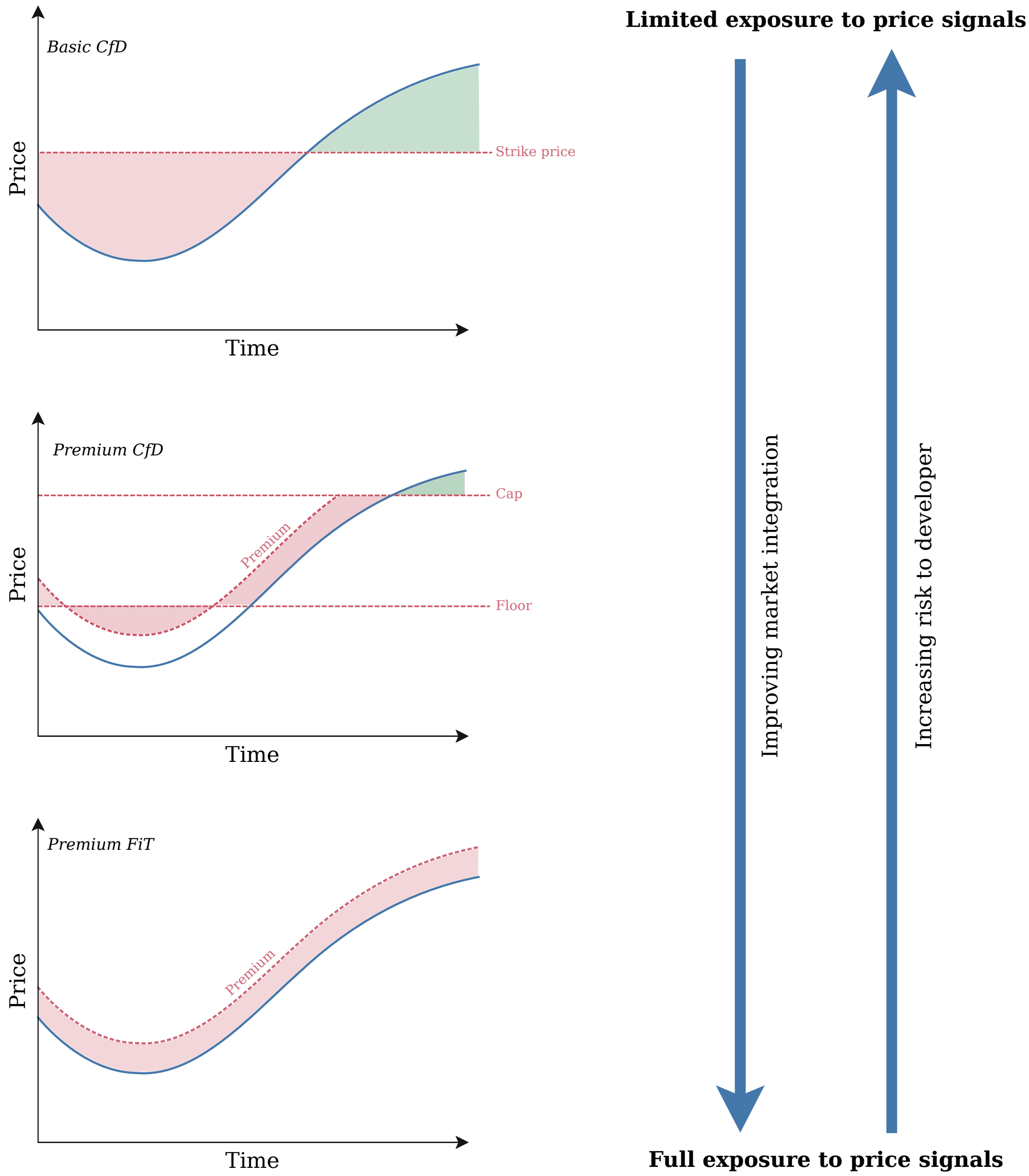

Figure 5: The variation in risk exposure and efficient market integration with the different structures discussed.

3 Auction evaluation principles

The Institute would like to raise two potential additional considerations for the auction evaluation priciples.

Scale Efficient Network Extension

While the Consultation Paper includes 'Electricity transmission network interactions' as an evaluation principle, explicit recognition for of Scale Efficient Network Extenstion could be considered. This evaluation criterion could take into consideration first mover disadvantages for projects that require or incure augmentation costs. Additionaly, the scheme could formally consider a consortium of project developers that includes network augmentation costs, rather than single projects.

Competition considerations

Market power and market concentration may emerge as an issue in coming years. Already, the Victoria energy market is dominated by four large participants that collectively control more than 80% of installed capacity.

The Herfindahl-Hirschman index (HHI) is a commonly used measure of market concentration reported and is reported annually by the AER in the 'State of the Energy' market report[5]. The HHI is a static metric, calculated by summing the squares of the percentage market shares for all firms participating in a market.

An HHI value of 10,000 is equivalent to a 100% share, and represents complete monopoly. An HHI value of 2000 is used by the ACCC to flag competition concerns[6], while the U.S Department of Justice considers markets to *unconcentrated* at below 1500, *moderately concentrated* at 1500-2500 and *highly concentrated* at 2500[7]. Perhaps more relevant to energy markets are the UK's Office of Gas and Electricity Markets (OFGEM) guidelines. The OFGEM regards an HHI exceeding 1000 as *concentrated* and above 2000 as *very concentrated*[8].

With a current HHI value of 2000[9], the Victorian electricity market would currently be considered quite concentrated by many measures. Should a withdrawal occur in Victoria in comming years, this value would be expected to increase. As such, diversity of ownership might be an important consideration for auction evaluation.

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[5] AER, *State of the energy market 2015*, page 60.

[6] ACCC, *Merger guidelines*, page 37.

[7] U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, pages 18 and 19.

[8] OFGEM, *Wholesale Energy Markets in 2015*, page 37.

[9] AER, *State of the energy market 2015*, page 60.